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# 14

## Integrated Dynamic Information for the Western Power System: WAMS Analysis in 2005

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## 14.1 Preface

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This chapter deals with the direct analysis of power system dynamic performance. By “direct” we mean that the analysis is performed on the physical system, and that any use of system models is secondary. Many of the tools and procedures are as applicable to simulated response as to measured response, however. Comparison of the results thus obtained is strongly recommended as a means to test model validity, and to determine the realism of model studies.

The resources needed for direct analysis of a large power system represent significant investments in measurement systems, mathematical tools, and staff expertise. New market forces in the electricity industry require that the “value engineering” of such investments be considered very carefully. Many guidelines for this can be found in collective utility experience of the Western Electricity Coordinating Council (WECC), in the western interconnection of the North America power system. Much of this is encapsulated in the WECC plan for compliance with monitoring requirements established by the North American Electric Reliability Council (NERC) [1]. The WECC monitors all aspects of system performance, not just system disturbances.

WECC compliance with NERC monitoring requirements is based on a general wide area measurement system (WECC WAMS). Figure 14.1 is provided as a guide to the associated geography, and to key interactions that govern wide area dynamics there. The WECC WAMS is both a distributed measurement system and a general infrastructure for dynamic information that conventional supervision control and data acquisition (SCADA) technologies cannot resolve. In addition to measurement facilities, the WAMS infrastructure also includes staff, procedures, and practices that are essential to effective use of WAMS data.

General reports concerning direct measurement and analysis of WECC system performance are usually available from Internet Web sites such as [ftp://ftp.bpa.gov/pub/WAMS\\_Information/](ftp://ftp.bpa.gov/pub/WAMS_Information/) or from WECC staff. This and related Web sites are routinely used for off-line exchange of data, working documents, and software associated with WAMS operation.

## 14.2 Examples of Dynamic Information Needs in the Western Interconnection

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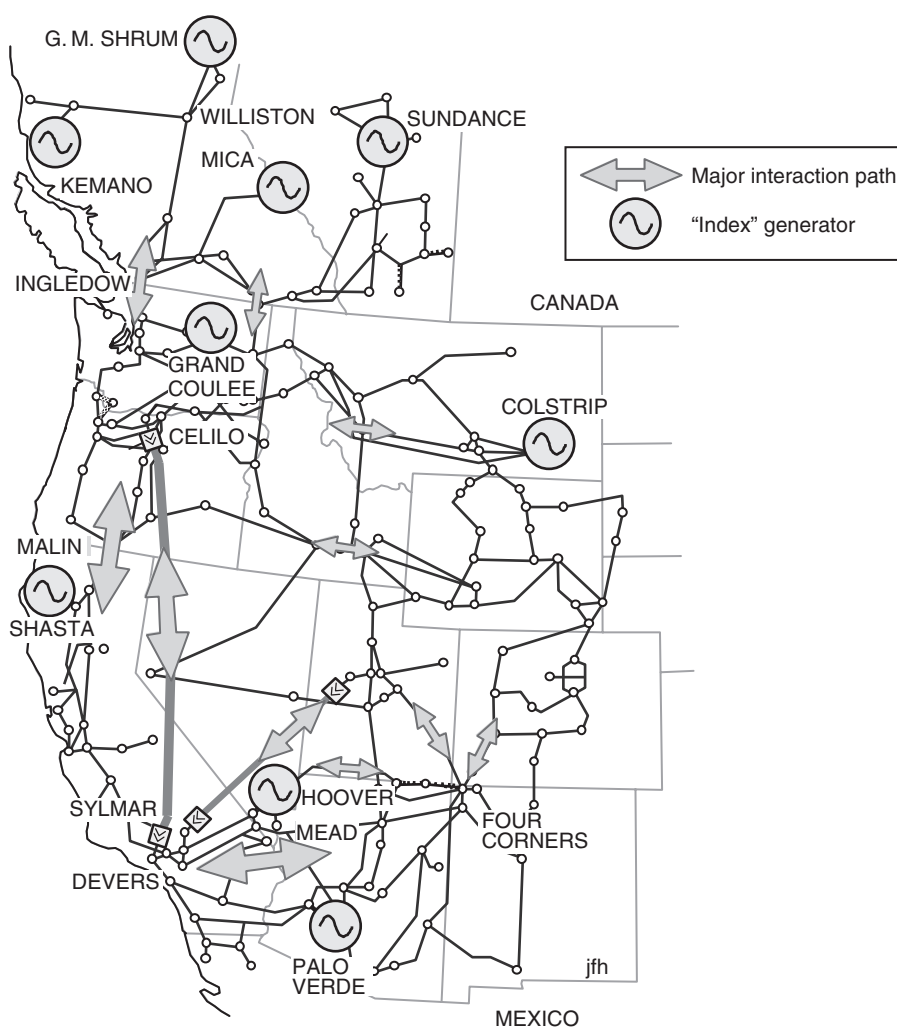
The WECC WAMS is a collective response to shared information needs in the western interconnection. Examples below show what sort of information is needed and why.

### 14.2.1 Damping Control with the Pacific HVDC Intertie

In 1976 the Bonneville Power Administration (BPA) installed a modulation system at the Celilo terminal of the Pacific HVDC Intertie (PDCI), for the purpose of damping intermittent oscillations on the Pacific AC Intertie (PACI). This is now called the California–Oregon Interconnection (COI) [2]. The Celilo Damper, in its final form, had a peak-to-peak modulation capability of 280 MW plus very strong leverage over at least four interarea modes below 1.0 Hz. The most important of these was the north–south mode between Canada and California–Arizona, often called the PACI mode.

The Celilo Damper influenced every generator in the western system, significantly, and in ways that were not always predictable or beneficial. The associated problems, trade-offs, and strategic issues carry over directly to the EPRI flexible AC transmission system (FACTS), and to any similar effort using wide area control to extend transmission capabilities [3,4].

Operating experience with the Celilo Damper underscored information needs that had not been fully appreciated. The PDCI itself is very complex, and the fast response normal to HVDC control provides a broadband interaction path for dynamic processes in the even more complex AC system (Fig. 14.2). It was soon found that AC/DC interactions exhibited behavior that could not be explained with existing models or with existing measurement facilities, and that some of the measurements themselves were



**FIGURE 14.1** Key location and interactions in the western interconnection.

suspect [5]. The western utilities then undertook a broad upgrade of both measurements and models, in what became known as the WAMS effort. Early reports on this are provided in Refs. [6,7].

Various findings specific to large-scale stability controls are detailed in Ref. [4], [Chapter 8](#), which deals with the field engineering of large-scale controllers. Chief among these is the conclusion that a damping controller which addresses global objectives needs a reliable source of global information. Requiring that all modulation signals be local can make controller siting a difficult robustness issue. There are many aspects of the controller environment which cannot be predicted from model studies, and which may not be measurable until the controller itself is available to probe system dynamics. Providing the controller (and the control engineer) with an ample reserve of directly measured dynamic information considerably enhances the options for project success.

## 14.2.2 Threat of 0.7 Hz Oscillations

Starting somewhere near 1985, WSCC model studies gave strong warnings of possible oscillations near 0.7 Hz. These were predicted for certain disturbances under stressed network conditions, such as loss of

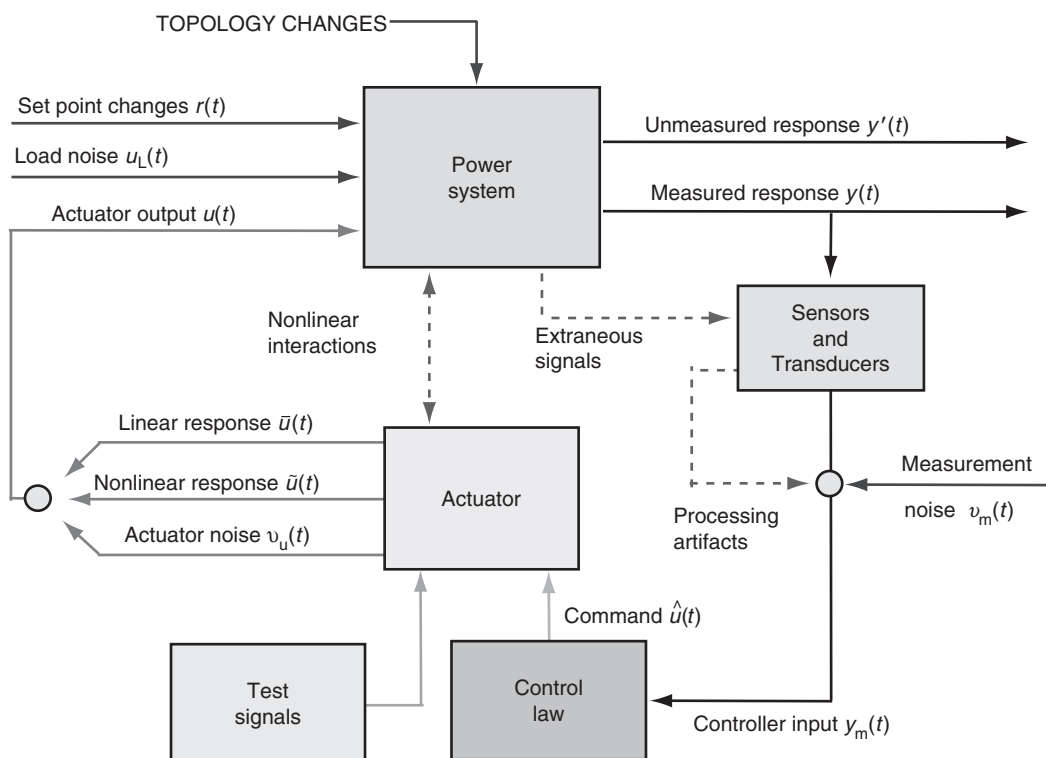


FIGURE 14.2 Operating environment for wide area damping control.

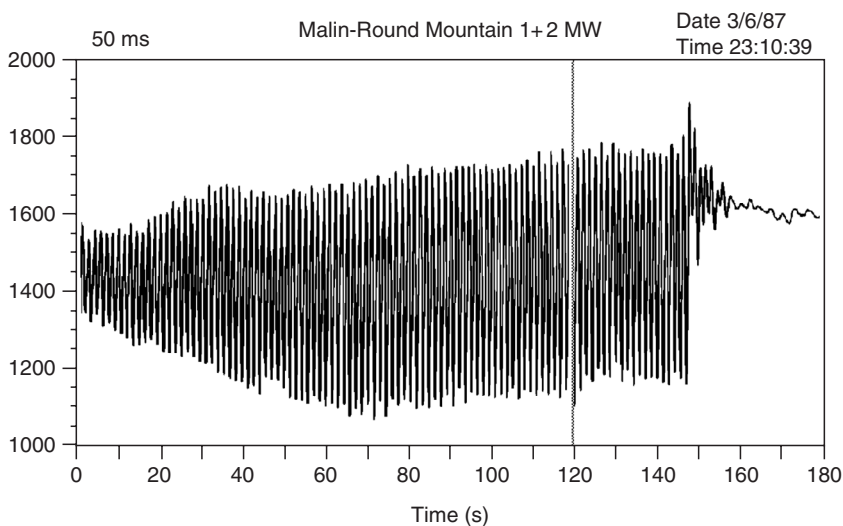
the PDCI. This perceived threat curtailed power transfers on the Arizona–California energy corridor, and it adversely impacted WSCC operation in a number of other ways as well. This enigmatic mode also inspired several damping control projects to mitigate it, and it produced a vast literature on the subject. These same model studies also had a strong tendency to understate the threat of north–south oscillations between Canada and California.

Oscillations near 0.7 Hz had been observed under ambient oscillations and, for the most part, were in the category of controller mischief. The only serious incident is shown in Fig. 14.3. The immediate problem was traced to a controller associated with the Intermountain Power Project (IPP) HVDC line, and it was promptly corrected. The controller bandwidth, about 1 Hz, was modest but still excessive in light of controller objectives and the uncertainties surrounding its dynamic effects.

The incident also illustrates several broader issues. One is that the engineering of a major control system often requires signals and support from neighboring utilities. Another is that transient oscillations present some formidable challenges to the control community.

Unlike oscillations that develop spontaneously under ambient conditions, transient oscillations may be large and violent at the onset. They may also be accompanied by abrupt changes in system topology and dynamics. Addressing the problem through large-scale transient damping controllers incurs the risk of what might be termed “The Star Wars Dilemma.” This calls for a very expensive control system that cannot be adequately tested in the field, but that must successfully perform a very-high-priority mission the first time it is needed. It also calls for good models and a “smart” controller [3].

The WSCC formed special work groups to address these issues. Results such as the model validation test are shown in Fig. 14.4 established that 0.7 Hz oscillations were largely a modeling artifact, and means to correct this were identified [6–8]. In the summer of 1996 model studies involving the north–south mode remained much too optimistic.

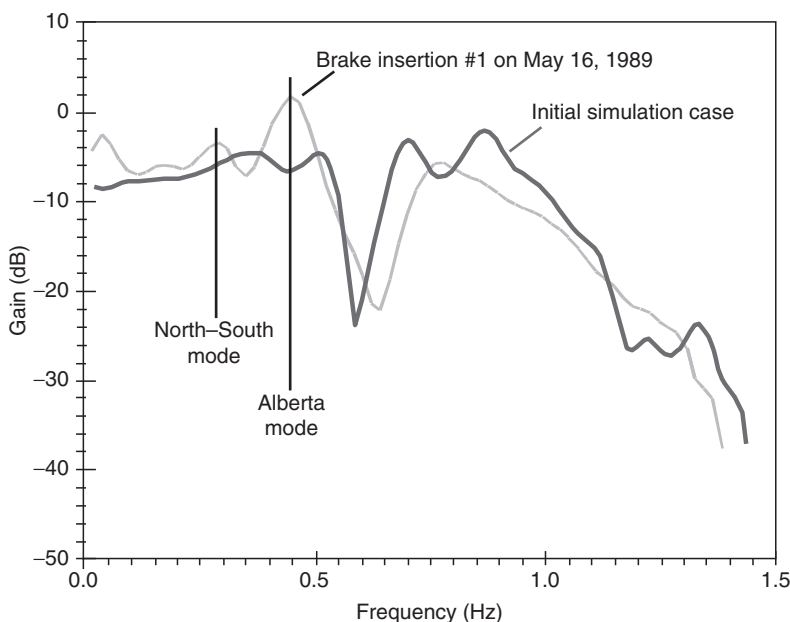


**FIGURE 14.3** 0.7 Hz oscillations on March 6, 1987.

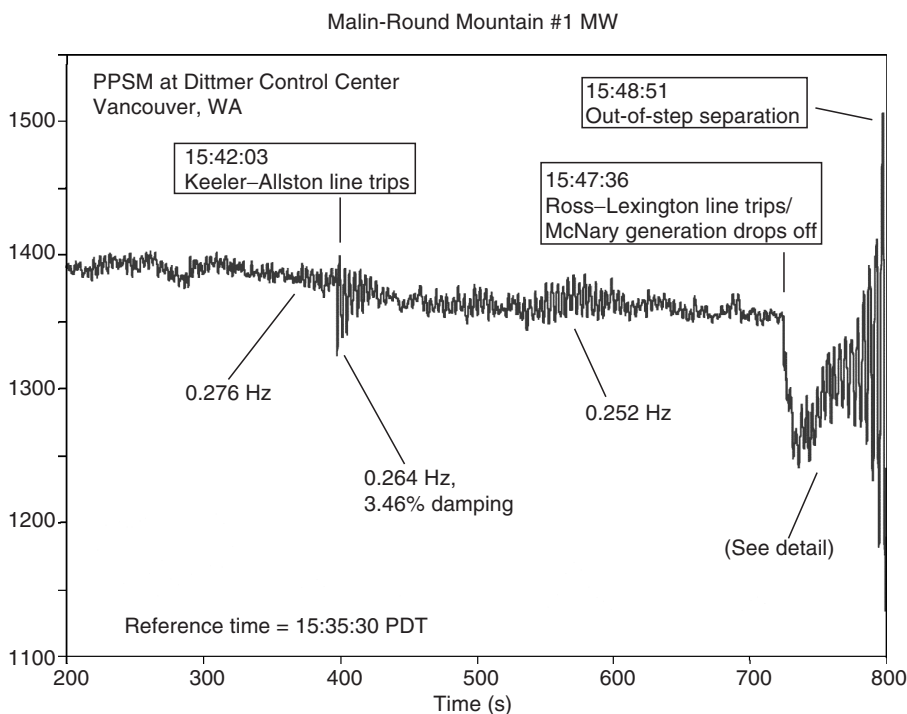
### 14.2.3 WSCC Breakup of August 10, 1996

Some grid managers, chiefly independent system operators (ISOs) and electrical utilities engaged in long distance transmission, are developing substantial measurement facilities. The critical path challenge is to extract essential information from the data, and to distribute the pertinent information where and when it is needed. Otherwise system control centers will be progressively inundated by potentially valuable data that they are not yet able to fully utilize.

These issues were brought into sharp and specific focus by the massive breakup experienced by the western interconnection on August 10, 1996. The mechanism of failure (though perhaps not the cause)



**FIGURE 14.4** Model vs. actual response of AC Intertie power to Chief Joseph brake power on May 16, 1989.



**FIGURE 14.5** Oscillation buildup for the WSCC breakup of August 10, 1996.

was a transient oscillation, under conditions of high power transfer on long paths that had been progressively weakened through a series of seemingly routine transmission line outages.

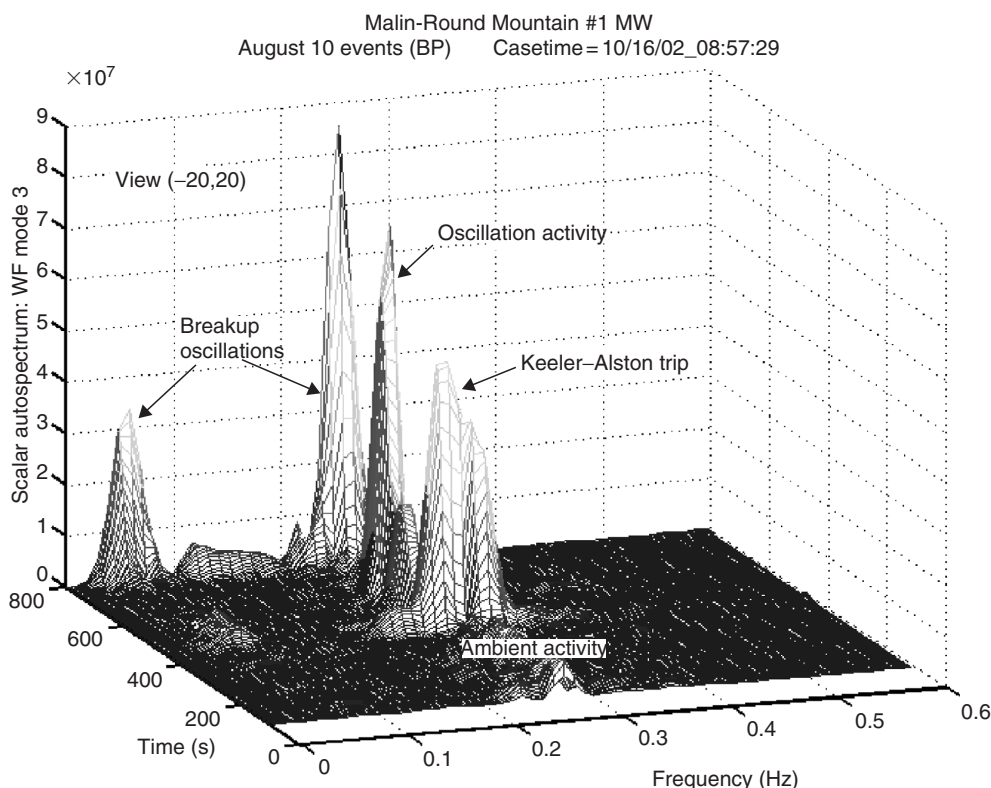
Buried within the measurements at hand lay the information that system behavior was abnormal, and that the system itself was vulnerable. Later analysis of monitor records, as in Figs. 14.5 and 14.6, provides many indications of potential oscillation problems (see Ref. [9] and Section 14.15.1). Verbal accounts also suggest that less direct indications of a weakened system were observed by system operators for some hours, but that there had been no means for interpreting them. The final minutes before breakup represented a situation that had not been anticipated, and for which no operational procedures had been developed.

This event was a warning that utility restructuring, through several mechanisms, was making it impossible to predict system vulnerabilities as accurately or as promptly as the increasingly volatile market demands. It is likely that standard planning models could not have predicted the August 10 breakup, even if the conditions leading up to it had been known in full detail [7,11]. This situation has deep roots and many ramifications [10–13].

An interim solution is to reinforce capabilities for predicting system vulnerability with the capability to detect and recognize its symptoms as evidenced in dynamic measurements. Much of the technology and infrastructure that this requires are being developed as extensions of the DOE/EPRI WAMS Project and related efforts [14–17].

### 14.3 Needs for “Situational Awareness”: US–Canada Blackout of August 14, 2003

US–Canada Blackout on August 14, 2003 was immediately notable for its extent, complexity, and impact. Among many other actions, the event triggered a massive effort to secure and integrate regional



**FIGURE 14.6** Oscillation spectra for the WSCC breakup of August 10, 1996.

operating records. Much of this was done at the NERC level, through the US–Canada Power System Outage Task Force [18,19].

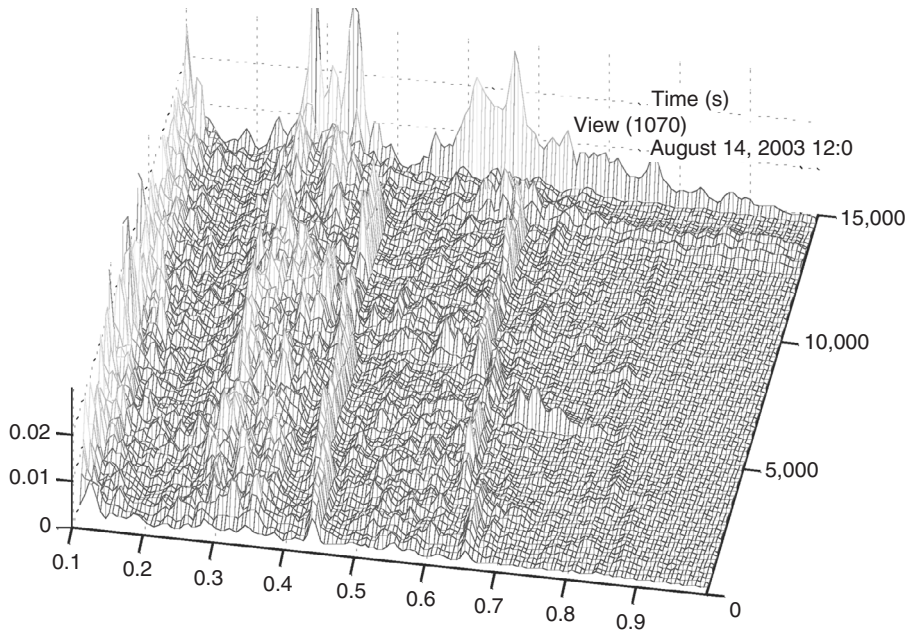
Additional background information concerning the event was gathered together by a group of utilities that, collectively, had been developing a WAMS for the eastern interconnection [20]. Like the WECC WAMS in the western interconnection, “WAMS East” had a primary backbone of synchronized phasor measurement units (PMUs) that continuously stream data to phasor data concentrators (PDCs) at central locations for integration, recording, and further distribution. Both WAMSs also employ portable power system monitor (PPSM) units as a secondary backbone, to continuously record analog transducer signals on a local basis [14].

WAMS data collected on August 14 provide a rich cross section of interarea dynamics for the eastern interconnection. Much of this information is imbedded in small ambient interactions, and is readily apparent to spectral analysis. Figure 14.7, for bus frequency fluctuations at the American Electric Power (AEP) Company Kanawha River substation, is typical of data that were collected as far away as Entergy’s Waterford substation near New Orleans, Louisiana.

Frequency of the spectral peaks shows a general downward trend, plus sharp discontinuities that are associated with system events. This behavior suggests that the “swing frequencies” associated with interarea modes were declining through increasing stress and network failures on the power system [21]. Though oscillation problems were not a significant factor in the August 14 Blackout, oscillation signatures such as those in Fig. 14.7 provide readily available information that can be factored into “situational awareness” for real-time operation of the overall grid.

The August 14 Blackout provided considerable stimulus to the preexisting Eastern Interconnection Phasor Project (EIPP) [22]. Progress in this effort can be tracked by examining the WAMS Web site <http://phasors.pnl.gov/>

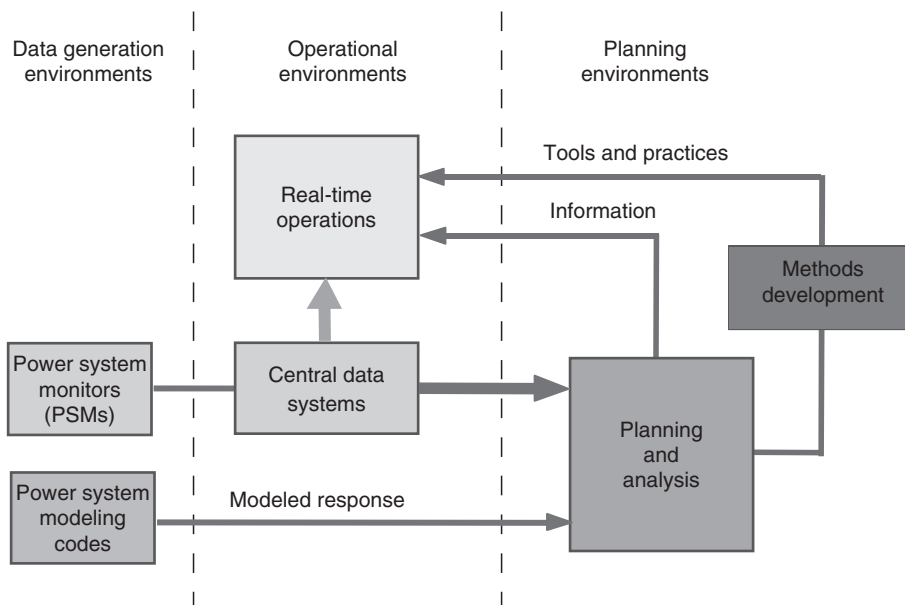




**FIGURE 14.7** Spectral history for US–Canada Blackout of August 14, 2003: AEP Kanawha River bus frequency, 12:00–16:10 EDT. Data provided by Navin Bhatt, AEP.

## 14.4 Dynamic Information in Grid Management

The WECC WAMS is embedded within the broader picture shown in Fig. 14.8. Data generated by measurements and models may be used in many different ways, and in many different time frames. The same measurements that system operators see in real time may contain benchmark performance



**FIGURE 14.8** The role of measurement-based information in planning and operations.

information that is valuable for years into the future. Such measurements may also be needed to determine the sequence of events for a complex disturbance, to construct an operating case model for the disturbance, or as a basis of comparison to evaluate the realism of power system modeling in general.

WAMS infrastructure is built around just two core objectives:

- Obtain good data, and keep them safe.
- Translate WAMS data to useful information, and promptly deliver that information to those who need it.

These outwardly straightforward objectives involve some rather complex issues. One of these is shared support for WAMS deployment and operation. Another is the balancing of grid management needs against the proprietary rights of data owners.

A major WAMS usually evolves incrementally, building upon existing resources to address additional needs. This implies a mixture of technologies, data sources, functionalities, operators, and data consumers. Some governing realities are the following:

- *System configuration* is strongly influenced by geography, ownership, selected technology, and the technology already in service (legacy systems).
- *Required functionalities* are determined by who should (or should not) see what, when, and in what form.

Overall, the forces at work strongly favor WAMSs that evolve as “networks of networks” through collaborative agreements among many parties.

There are advantages to this situation. Interleaving networks that have different topologies and different base technologies can make the overall network much more reliable, while broadening the alternatives for value engineering. It also permits utility level networks to be operated and maintained on the basis of ownership, and permits a utility to withhold certain data until they are no longer sensitive. Disadvantages include protracted reliance upon obsolescent or incompatible equipment types, plus various institutional impediments to sharing of costs and timely information. These are major factors in the deployment, operation, and value of the WAMS infrastructure.

## 14.5 Placing a Value on Information

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The main thrust of the WAMS effort is to suitably incorporate measurement-based information into the grid management process. Planning the necessary investments encounters a very basic question: just how do you place a value on information? A partial answer is this:

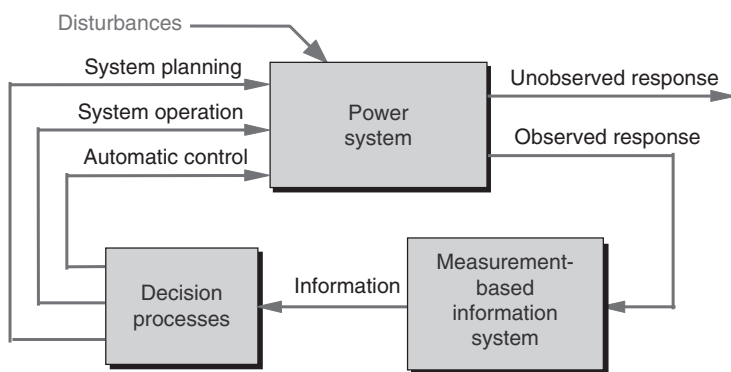
*The value of information is precisely that of the decisions derived from it.*

The paradigm of [Fig. 14.9](#) is useful for expanding upon this statement.

Decision processes in a power system range from the very rapid ones preprogramed into protective control equipment to the very slow ones associated with expansion planning. In all cases the decisions are derived, with varying degrees of immediacy, from system measurements. In some cases the extracted information is encapsulated in a model, or perhaps in operating policies. In others the data are processed immediately—e.g., as a controller input or as a signal to system operators.

Accumulated over time, information provides a knowledge base that permeates utility practices and those of the industry. Such long-term effects, together with the multiplicity of paths by which information enters utility decision processes, will defeat any direct attempt to place a value upon it. More constructive results follow from considerations of affordability and risk management:

- *Consider information an insurance policy* against operational uncertainty:
  - How much insurance is enough?
  - How much risk is too much?
- *Distinguish between value, cost, and affordability.*
- *Consider all cost elements*, especially lead time and staff demands.



**FIGURE 14.9** The cycle of measurement, information, and decisions.

Another factor, one that may preempt many of these considerations, is regulatory mandates issued by NERC and at various levels of government [23]. It is likely that an infrastructure for developing and exchanging dynamic information will be found necessary for assuring power system reliability and, thereby, the public interest.

## 14.6 An Overview of the WECC WAMS

The WECC WAMS is designed to serve the specific applications listed in Table 14.1. Many other objectives are implicit in this, and other electrical interconnections might state or prioritize their objectives differently.

Annual reports on deployment and use of the WECC WAMS are available on the associated Web sites. The description presented here is based on the 2004 report [17].

Regular operation of the WECC WAMS involves about 1400 “primary” signals that are continuously recorded in their raw form. These primary signals are the basis for several thousand derived signals that are viewed in real time, or during off-line analysis of power system performance. Data sources are of many kinds, and they may be located anywhere in the power system. This is also true for those who need the data, or those who need various kinds of information extracted from the data.

The primary “backbone” for the WECC WAMS consists of phasor networks as represented in Fig. 14.10. PMUs stream precisely synchronized data to PDC units, and the PDCs stream integrated PMU data to StreamReader units and sometimes to other PDCs. The StreamReaders provide display, continuous archiving, and add-on functionalities such as spectral analysis or event detection. Remote dial-in access to PDC and StreamReader units is available when security considerations permit.

**TABLE 14.1** Key Applications of the WECC WAMS

- |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"> <li>• Real-time observation of system performance</li> <li>• Early detection of system problems</li> <li>• Real-time determination of transmission capacities</li> <li>• Analysis of system behavior, especially major disturbances</li> <li>• Special tests and measurements, for purposes such as             <ul style="list-style-type: none"> <li>– special investigations of system dynamic performance</li> <li>– validation and refinement of planning models</li> <li>– commissioning or recertification of major control systems</li> <li>– calibration and refinement of measurement facilities</li> </ul> </li> <li>• Refinement of planning, operation, and control processes essential to best use of transmission assets</li> </ul> |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|

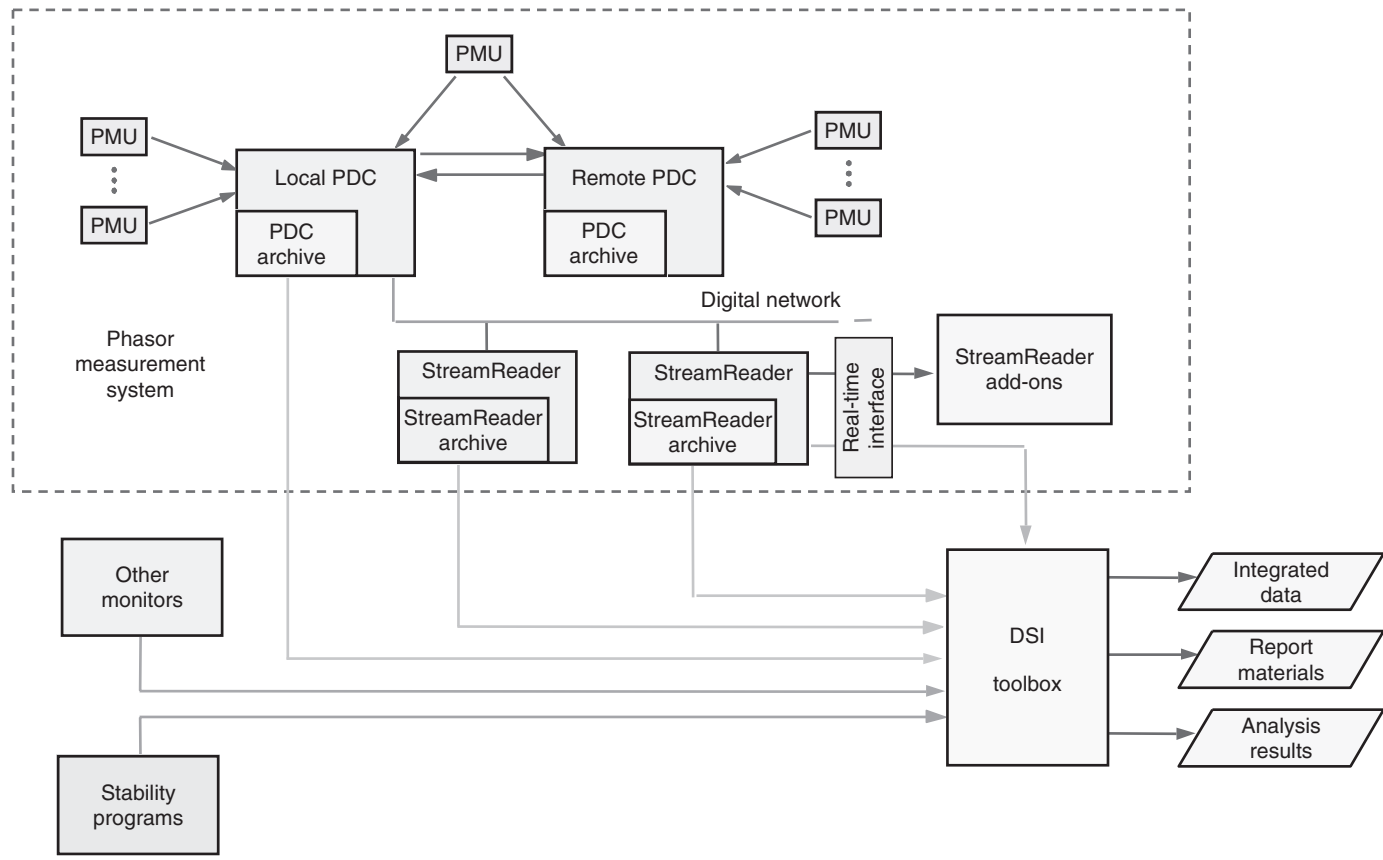


FIGURE 14.10 Flow of multisource data within an integrated WAMS network.

**TABLE 14.2** Inventory of WECC Monitor Facilities, February 2004

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|                                                                              |
|------------------------------------------------------------------------------|
| Phasor measurement facilities (continuous recording, 30 sps)                 |
| 56 integrated PMUs                                                           |
| 15 stand-alone PMUs (local archiving downloaded to Alberta ISO upon request) |
| 7 primary PDCs (7 data sharing links)                                        |
| 1 data access PDC (at California ISO)                                        |
| 478 phasors                                                                  |
| ~956 primary signals ( $2 \times$ number of phasors)                         |
| PPSM units (continuous recording, 20–2000 sps)                               |
| 1 central unit (plus backup) for RMS signals                                 |
| 17 local units for RMS signals                                               |
| 5 local units for point on wave signals                                      |
| ~600 primary signals                                                         |
| Monitors of other kinds (triggered recording, excludes DFRs)                 |
| 5–20 local units                                                             |
| ~100 primary signals                                                         |

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Each PDC has the potential of providing real-time data for power system behavior across a broad region of the power system. Some PDCs share signals to extend this coverage, and higher level networks are evolving that will consist of PDCs entirely. For the present, however, most of the directly integrated phasor networks are isolated from one another and the data they collect are selectively integrated off-line (Table 14.2).

The WECC WAMS of 2004 is well along in the transition from synchronized phasor measurement (SPM) networks to a much more general synchronized system measurement (SSM) network that accommodates signals of all kinds [24,25]. Recent progress items in this area include:

- SPM networks in western Canada
- Publication of the de facto BPA standard for PDC networks [24]. This is readily expanded into an SSM standard
- A growing WECC network of PDC units that share data in real time
- Deployment of local PMU/StreamReader packages tailored to generation facilities
- Deployment of high-speed GPS synchronized monitors that continuously record point on wave data, or signals from FACTS-like controllers
- A growing dialog with vendors of control equipment concerning export of signals into a general SSM network

The phasor networks in Canada are especially welcome. Oscillatory dynamics in the western interconnection are strongly influenced by large plants on the far edges of the network. In the northern part of the system at least four plants are noteworthy in this respect. The Kemano, G.M. Shrum, Sundance, and Colstrip plants all feed power into the main grid through long radial connections. The size of these plants, together with the long connections, exercises a major role in the interaction patterns for associated interarea modes below 1 Hz. Generator controls at these plants have considerable influence upon damping of the associated modes, and correct modeling of these plants is especially important to valid planning studies. Even when damping and modeling are not of immediate concern, the plants are still of special interest as sources of information and understanding about wide area dynamics.

Figure 14.11 shows the PDC units that are operational in the WECC, plus the linkages among them. Several types of PMU are in service, from at least four commercial vendors. The PDC units and the StreamReader units are BPA technology.

Signals collected on the WAMS backbone are continuously recorded at a rate of 20, 30, or 240 samples per second (sps); about half of the signals are phasor measurements. When needed, data from local monitors are integrated with data collected on the PDC network to form more detailed records of system behavior in areas of special interest. Some of the local monitors are “snapshot” disturbance monitors



Wide area monitoring for a large power system involves the following general functions:

- *Disturbance monitoring*, characterized by large signals, short event records, moderate bandwidth, and straightforward processing. Highest frequency of interest is usually in the range of 2 Hz to perhaps 5 Hz. Operational priority tends to be very high.
- *Interaction monitoring*, characterized by small signals, long records, higher bandwidth, and fairly complex processing (such as correlation analysis). Highest frequency of interest ranges to 20–25 Hz for RMS quantities but may be substantially higher for direct monitoring of phase voltages and currents. Operational priority is variable with the application and usually less than for disturbance monitoring.
- *System condition monitoring*, characterized by large signals, very long records, very low bandwidth. Usually performed with data from SCADA or other EMS facilities. Highest frequency of interest is usually in the range of 0.1 Hz to perhaps 2 Hz. Core-processing functions are simple, but associated functions such as state estimation and dynamic or voltage security analysis can be very complex. Operational priority tends to be very high.

These functions are all quite different in their objectives, priorities, technical requirements, and information consumers. At many utilities they are supported by separate staff structures and by separate data networks.

## 14.8 Interactions Monitoring: A Definitive WAMS Application

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The western interconnection is characterized by incessant dynamic interactions among generator groups and the various power system controls. These interactions, indicated in [Fig. 14.1](#), often extend across the entire system. Technologies used in the WECC WAMS are designed to examine and assess this activity.

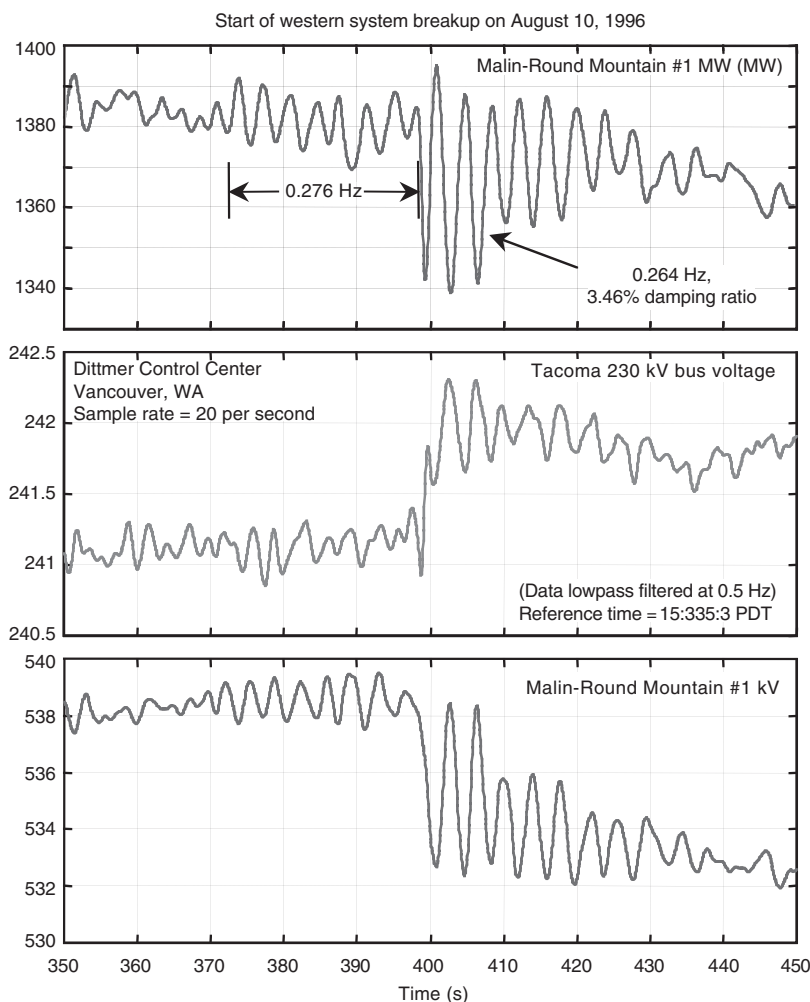
[Figure 14.12](#) illustrates interaction levels observed in analog transducer signals for the western system breakup of August 10, 1996. At Malin the 0.276 Hz precursor oscillations in the MW signal, just before the decisive line trip, constitute roughly 1% of the total signal, and the associated voltage oscillations there constitute perhaps 0.2% of the total signal. [Figure 14.13](#) shows torsional oscillations at roughly these same percentages. Close analysis of such signals, to detect trouble on the system or to assess controller effects, requires a signal resolution that is about 20 times smaller.

Examination of other signals and other sites indicates that transducer resolution, expressed as a fraction of full dynamic range, would ideally be in the vicinity of one part in 10,000 (0.01% or 80 dB). The resolution of top quality analog transducers approaches this value, and that of some PMUs or other digital transducers may even exceed it.

For many purposes it is necessary to determine the pattern, or *mode shape*, of dynamic interactions. An important case of this is shown in [Fig. 14.14](#) plus the Prony analysis “compass plot” of [Fig. 14.15](#) [31]. The relative strength and phase of the signals indicate the dominant activity was the Colstrip plant in eastern Montana swinging against the Williston area of British Columbia, in what may be an east–west counterpart to the north–south interaction that lead to the WSCC breakup on August 10, 1996. [Figures 14.16](#) and [14.17](#) show an outwardly similar event on October 9, 2003, but with far smaller oscillations at Williston.

Both events represent new and unusual behavior in the WECC system that is not well understood, and for which WECC modeling is not entirely accurate. Mode shapes, by revealing the degree to which specific generators and paths are involved in the oscillation mode, provide essential information for resolving both uncertainties. Mode shapes are also a key tool for distinguishing between different interactions that have similar frequencies, and for comparing dynamic events for which the frequencies of key modes have shifted.

Mode shape analysis is perhaps the most demanding application for WAMS data. The instruments at key sites must resolve small oscillations with sufficient detail to establish their modal composition



**FIGURE 14.12** Shift of western system dynamics with loss of Keeler–Alston 500 kV line. Start of WSCC breakup on August 10, 1996.

(frequencies and dampings). And, in addition to this, the overall measurement system must present an integrated portrait of the oscillation in which the instrument signals are consistent enough to establish the mode shape for each oscillation component.

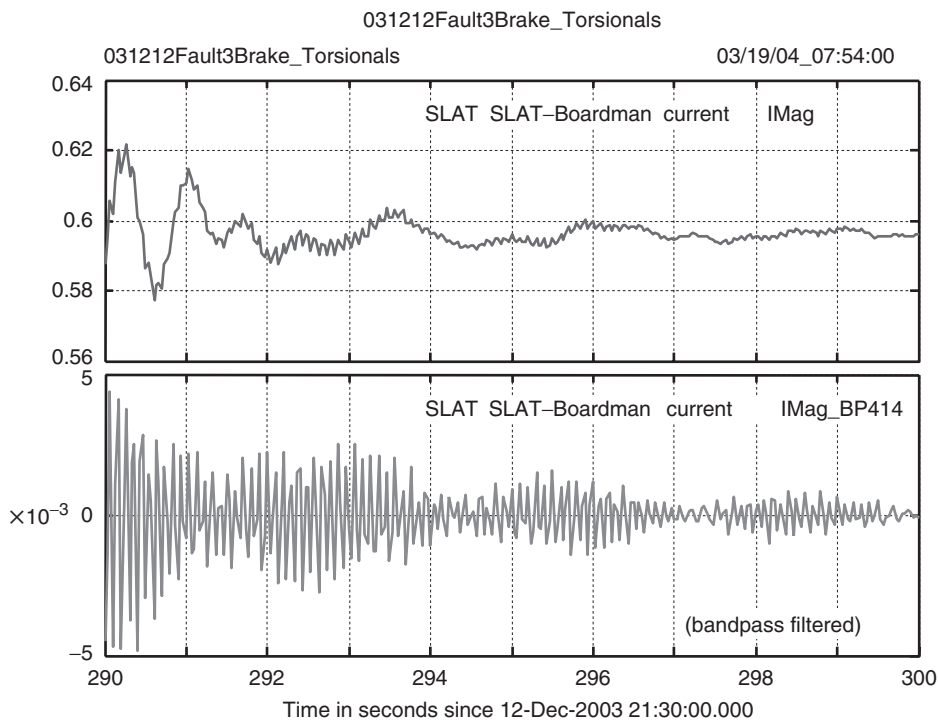
The effective resolution of particular signals can often be improved through filtering, correlation analysis, or model fitting. Figure 14.18 demonstrates that the Prony fitting procedure smoothes and processes low-frequency oscillations quite accurately. Enhancing the timing consistency of acquired signals can be less straightforward.

## 14.9 Observability of Wide Area Dynamics

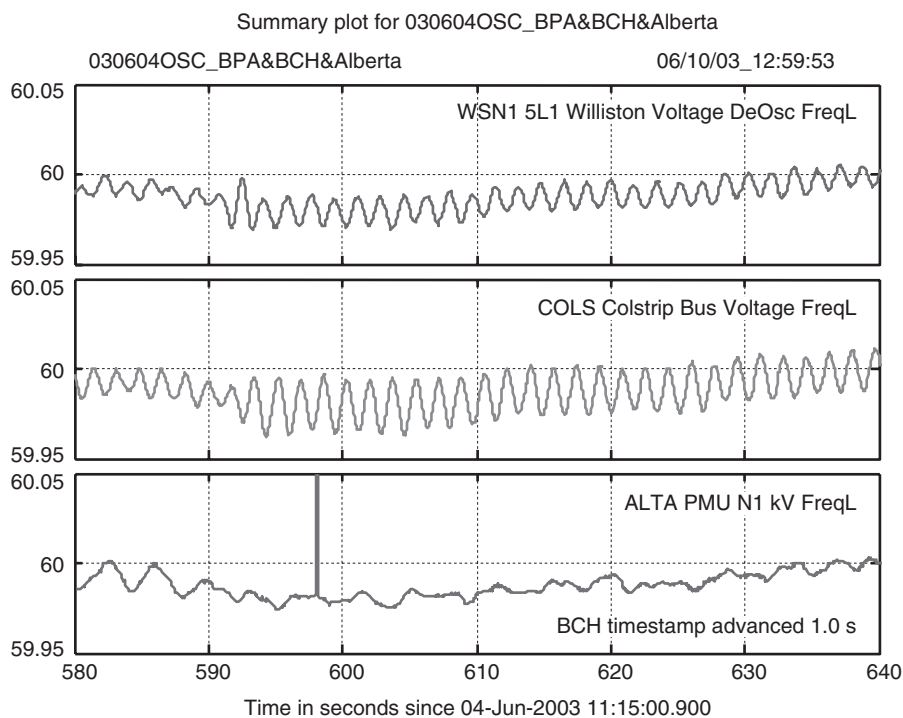
Close examination of WAMS data will, over time, provide insight into behavior of the power system and of the WAMS itself. This requires many operating conditions and events, with special attention to events that permit cross validation of WAMS data sources.

Switching events generally produce a signature like that in Fig. 14.19. Frequency transients at electrically remote sites, like the Sundance plant in Alberta, involve many low-frequency generator





**FIGURE 14.13** Torsional signatures in current magnitude on the Slatt-Boardman line Malin fault on December 12, 2003.



**FIGURE 14.14** Key frequency signals for NW oscillation event on June 4, 2003.

caseID = 030604OSC\_BPA&BCH&AlbertaBP casetime = 06/10/03\_12:59:53

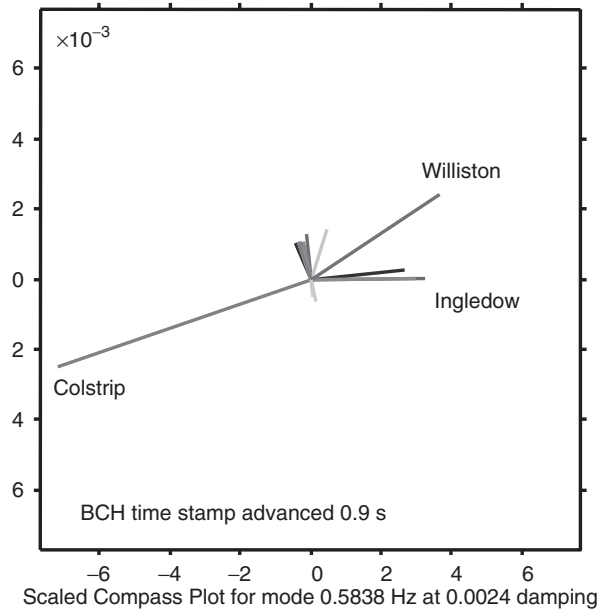


FIGURE 14.15 Mode shape for 0.584 Hz oscillation in local frequency NW oscillation event on June 4, 2003.

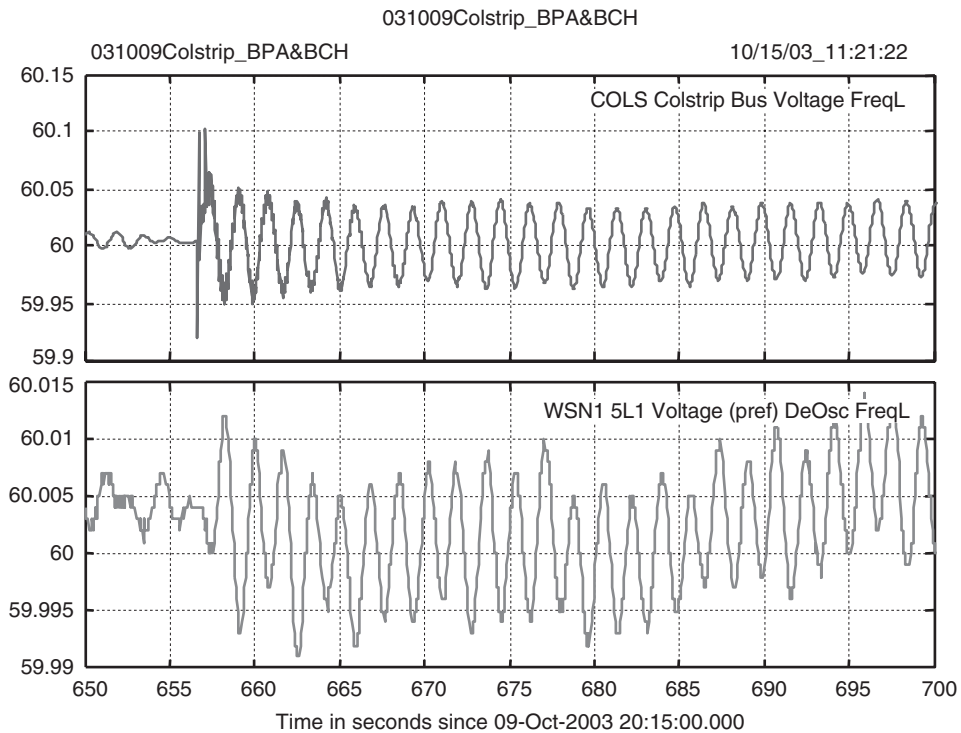
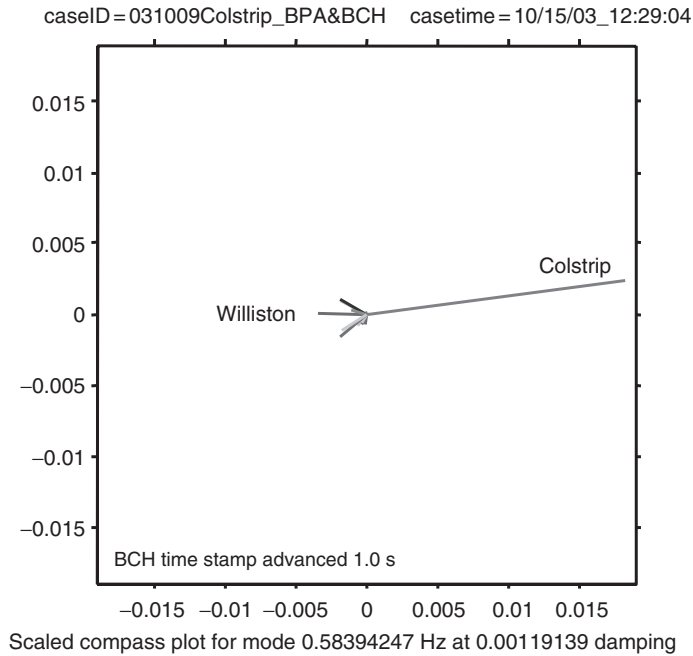


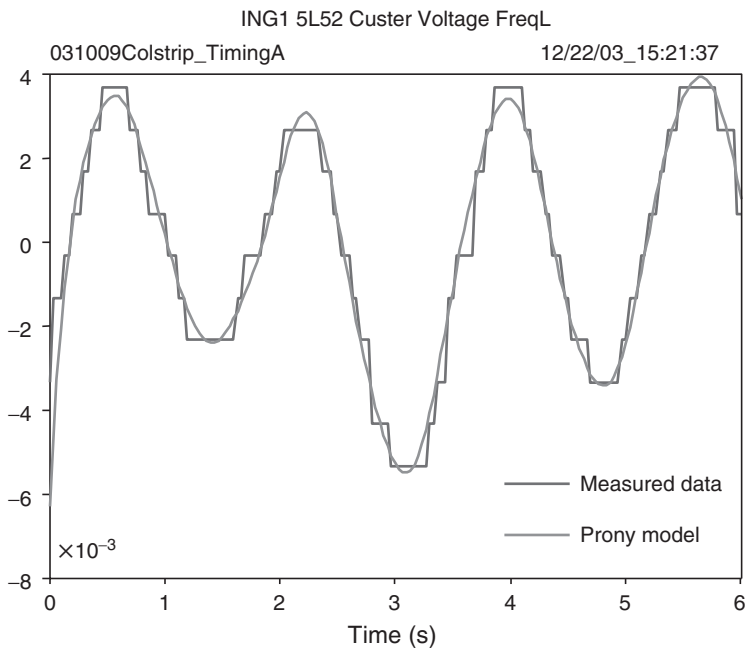
FIGURE 14.16 Key frequency signals for NW oscillation event on October 9, 2003.



**FIGURE 14.17** Mode shape for 0.584 Hz oscillation in local frequency NW oscillation event on October 9, 2003.

interactions and resemble the step response of a high order filter. Their starting points are usually not apparent to direct examination, and their use in record alignment checks may produce poor results.

Voltage magnitude and voltage angle generally produce sharper signatures for record alignment, provided that the voltage transient penetrates far enough into the transmission network. Examples below show that bus faults can be very useful for this.



**FIGURE 14.18** Typical Prony fit to NW oscillation on October 9, 2003.

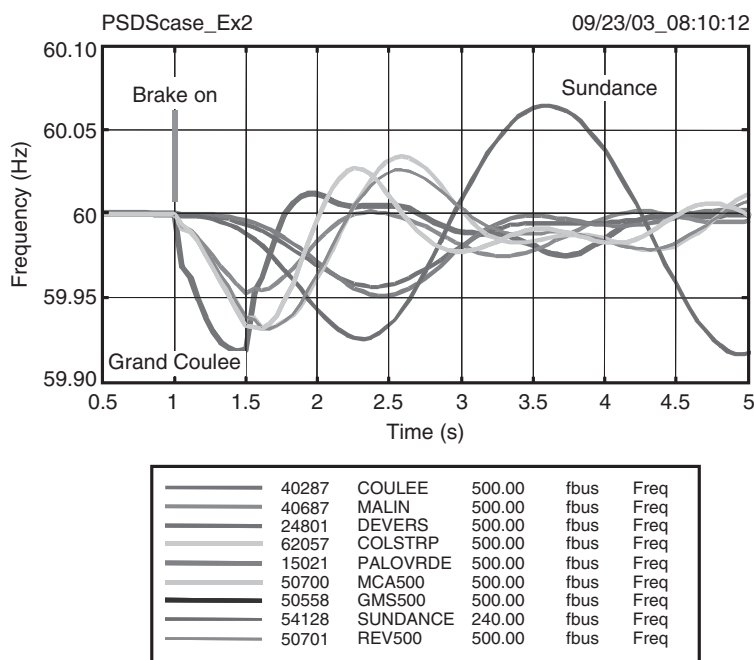


FIGURE 14.19 WECC simulation case for insertion of the Chief Joseph brake.

### 14.9.1 WECC Event 031212: Three-Phase Fault at Malin

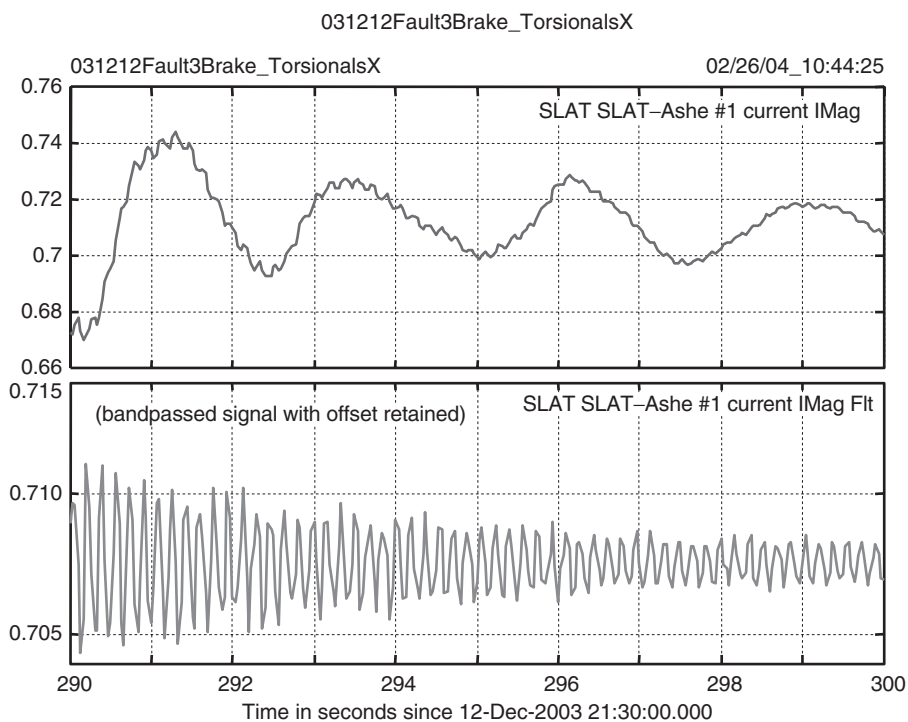
Three phase faults on major transmission facilities are rare events. However, severe weather during the winter of 2003–2004 caused at least two such events in the Malin area. On December 12, 2003 a fault plus protective control actions launched sharp voltage transients that were observable to PMUs throughout much of the western interconnection.

This transient produced conspicuous high-frequency ripples in signals along the Ashe–Slatt leg of the COI, as indicated in Figs. 14.13 and 14.20. Peaks in Fig. 14.21 match known frequencies for generator shaft oscillations at the Columbia Generating Station (CGS) near Ashe substation, and at the Boardman plant [17]. These plants are near McNary dam on the Columbia River, and some 280 miles from Malin.

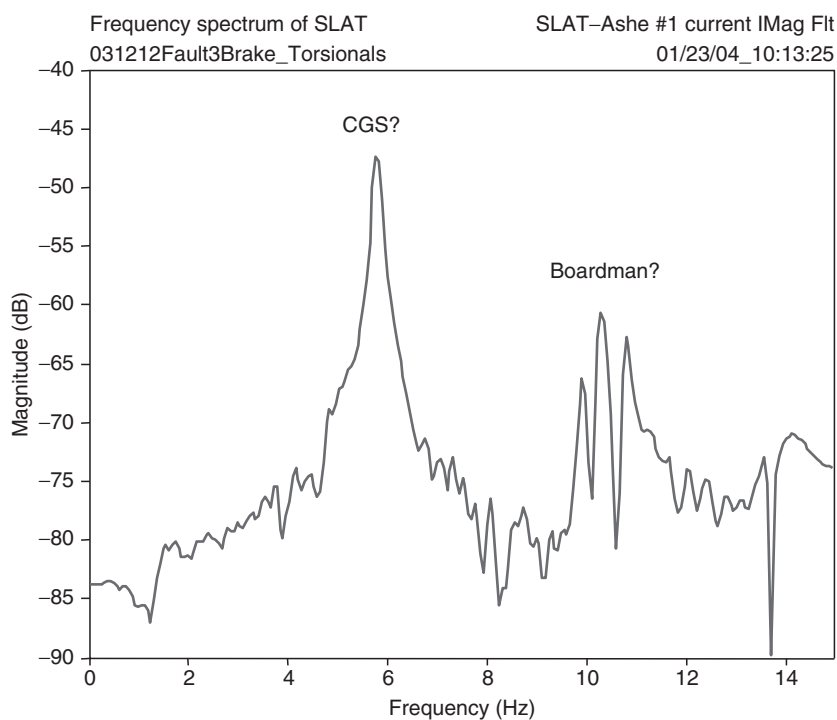
Voltage transients from this fault were observable as far away as Colorado, and provided a useful check on the alignment of PMU and PDC records. Figure 14.22 shows good consistency among voltage phasors collected on BPAs PDC units. Locations for these signals extend from eastern Montana to the west coast of the United States, and southward along the coast to southern California. A similar degree of consistency between BPA and WAPA records is shown in Fig. 14.23. Though the voltage magnitude transients in WAPA signals was too small to verify record alignment, the angle transients were quite suitable for this purpose. The PMU at Bears Ears is located near Denver Colorado, and is some 700 miles from Malin.

### 14.9.2 WECC Event 030604: Northwest Oscillations

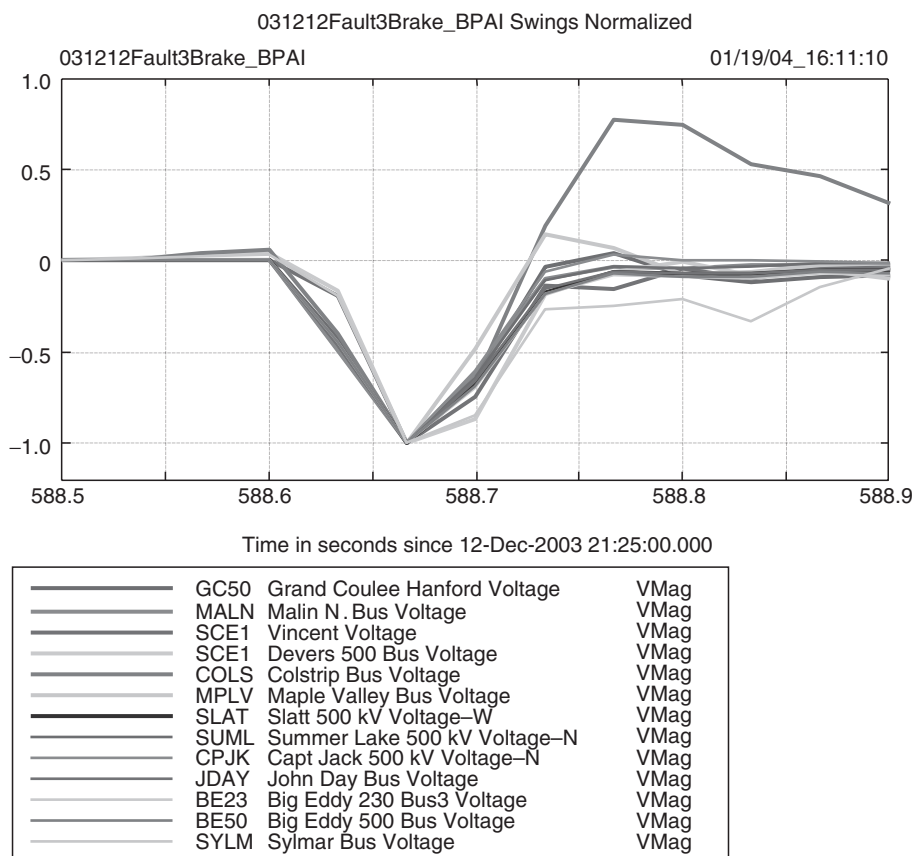
The oscillation shown in Fig. 14.14 was first observed as voltage cycling in SCADA displays for the Spokane area in eastern Washington State. Phasor data collected at BPA and BCH soon revealed this as a small but widespread oscillation at a steady frequency of 0.584 Hz. Figure 14.24 shows that this frequency was dominant, though some lower frequency modes were present. Mode shape identifies this as the Kemano mode, though frequency of the Kemano mode is usually about 0.63 Hz.



**FIGURE 14.20** Torsional signatures in current magnitude on the Slatt-Ashe #1 line Malin fault on December 12, 2003.



**FIGURE 14.21** Torsional signatures on the Slatt-Ashe #1 line (signals have been bandpass filtered) Malin fault on December 12, 2003.



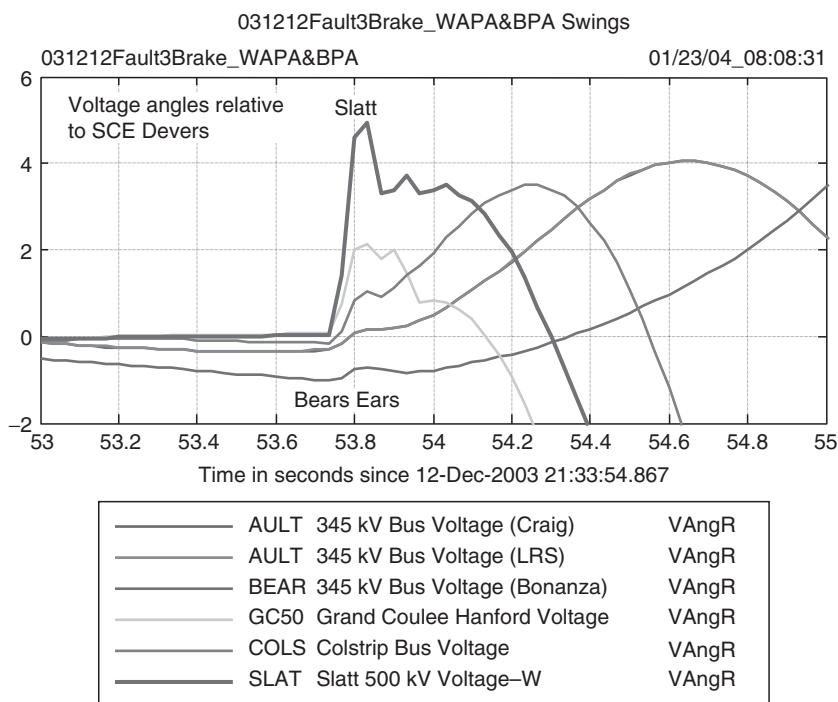
**FIGURE 14.22** Transients in normalized voltage magnitude Malin fault on December 12, 2003.

Correlation against MW swings on the Williston–Kelly Lake line revealed corresponding power oscillations on key tielines throughout the system, including very small ones on the PDCI. [Figure 14.25](#) shows that the interaction was clearly apparent in the coherency function for the Palo Verde–Devers line, even though this line is some 1400 miles from Williston and the signal is barely visible in the time-domain data of [Fig. 14.26](#).

The primary objective of this broader analysis is to understand the event, but an important secondary objective is to validate the measurements. Small oscillations at the frequency of an interarea mode can well be something else, such as aliased signals or instrument artifacts. Both PMUs in [Fig. 14.27](#) have the same inputs. Voltage magnitude signals from the older unit, PMU A, show a parasitic oscillation that is proportional to the voltage angle. This is easily mistaken for an actual power system oscillation, in part, because similar activity is displayed by similar PMUs in the region. Comparison against current signals and/or instruments of other types reveals it as a processing artifact, however.

## 14.10 Challenge of Consistent Measurements

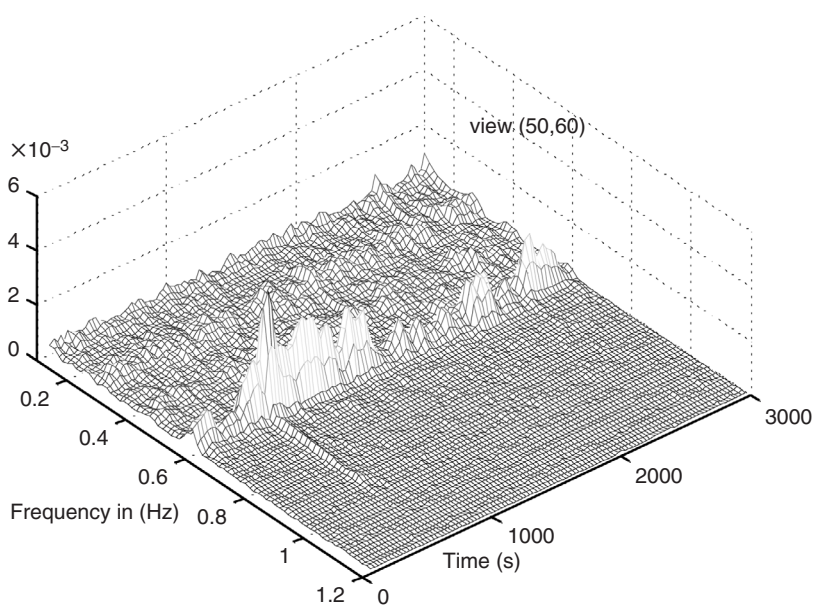
A major challenge to integrated processing for a large WAMS is to assure that measurements from the various data sources are consistent. Dissimilar filtering among analog instruments is a notorious cause of inconsistent signals, and some signals may require special compensation [32]. Digital technologies, and phasor measurements in particular, offer a welcome opportunity to avoid this burden. Many details



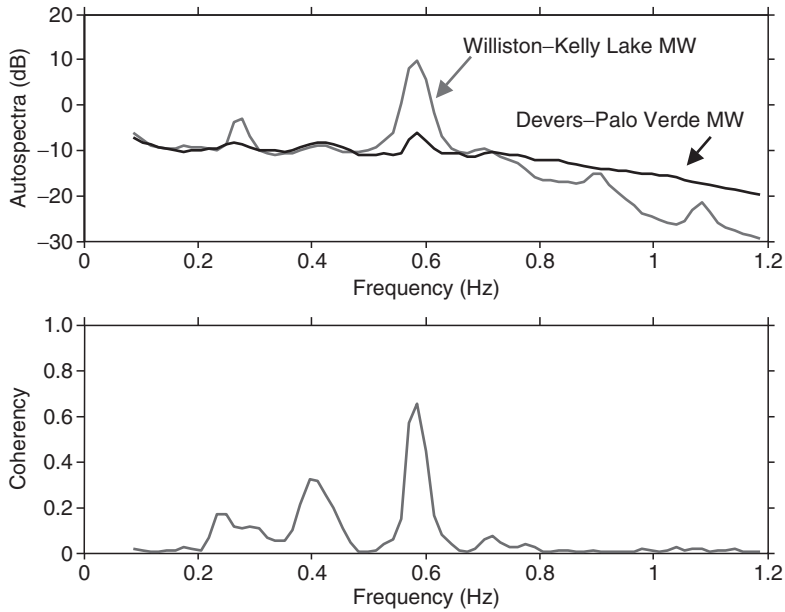
**FIGURE 14.23** Transients in voltage angles relative to SCE Devers Malin fault on December 12, 2003.

remain unresolved, however, and cross validation of multisource data remains a necessary precaution in the analysis of major system events.

Phasor instruments and phasor networks represent new technologies that are still adapting to a very wide range of situations. Once installed, a PMU will very likely undergo one or more upgrades. Some of



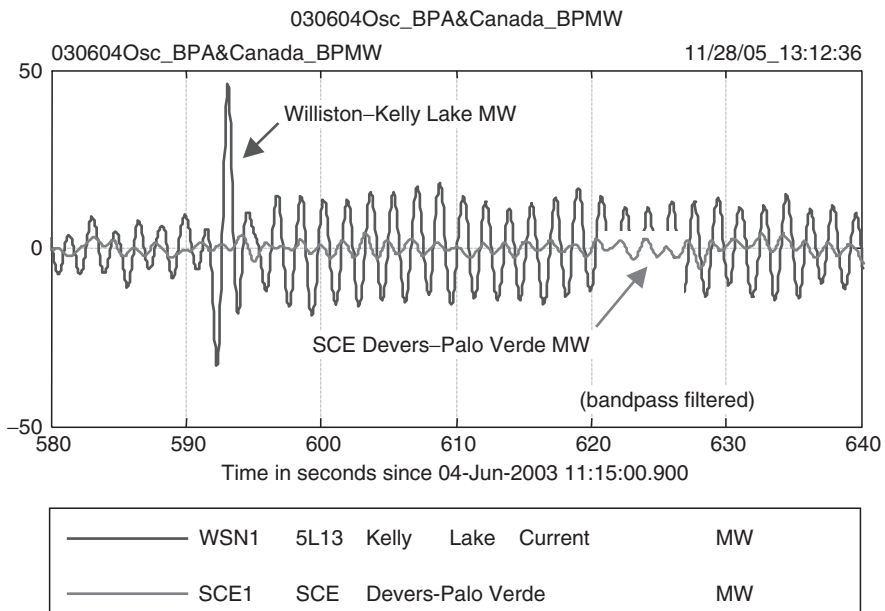
**FIGURE 14.24** Waterfall plot for oscillation on June 4, 2003—local frequency at Williston.



**FIGURE 14.25** Correlation functions for MW oscillations on June 4, 2003.

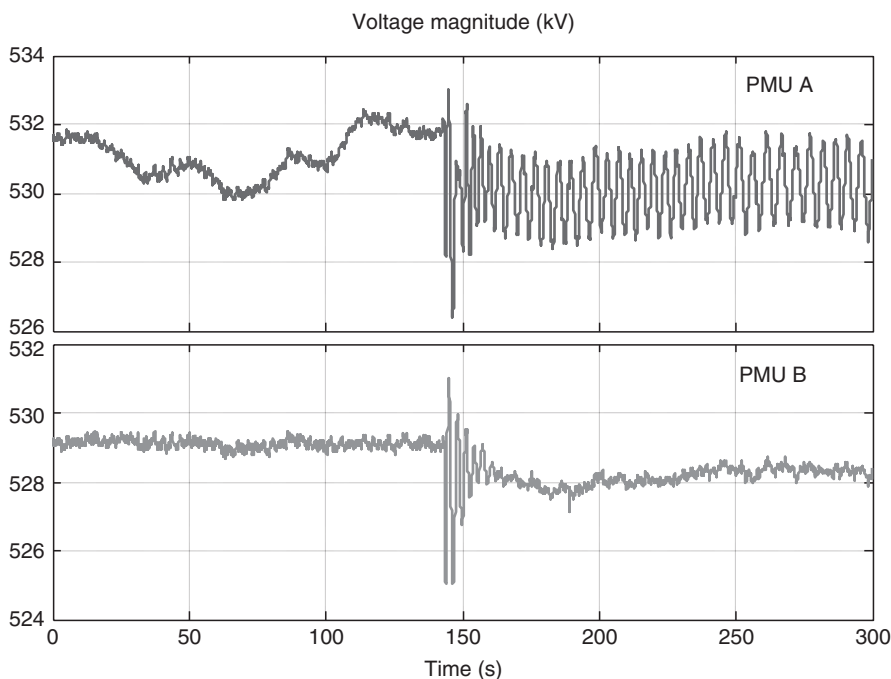
these upgrades may significantly change the dynamic response of the instrument and/or the degree to which its outputs are consistent with outputs from other units.

Anomalies, once detected, are usually corrected within days to weeks. Important records may be acquired before that time, however, and it is not unusual for the correction of one PMU anomaly to reveal or produce yet another one. This leads to a data archive in which some signals must be repaired or



**FIGURE 14.26** MW oscillations on June 4, 2003.





**FIGURE 14.27** Parasitic oscillations in an older PMU (PMU A).

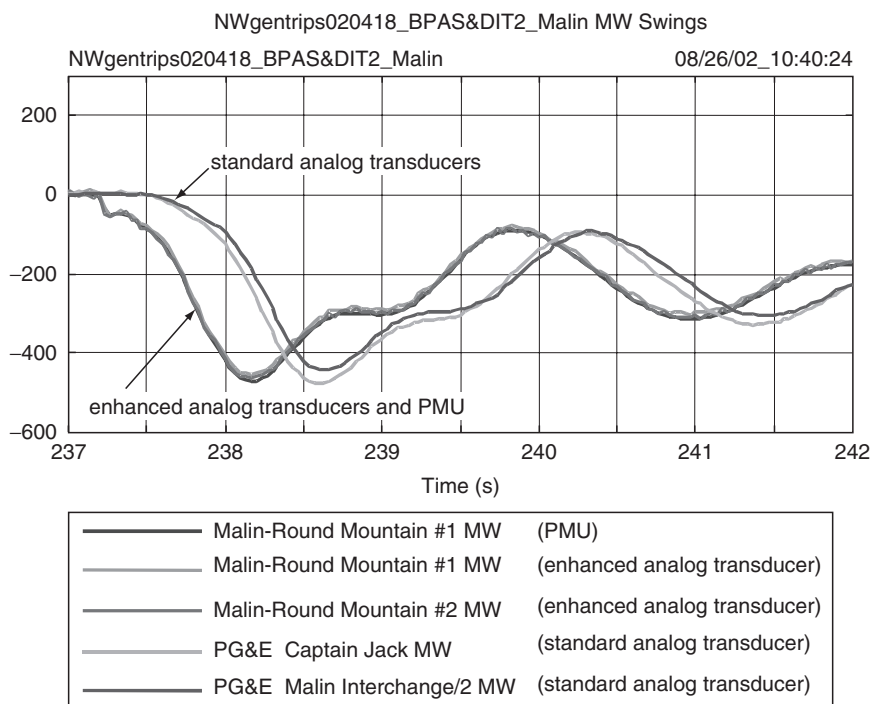
compensated in different ways for different recording times. Sometimes the need and the information to do this are not revealed until well after the data are recorded. A comprehensive log of PMU configuration and firmware is essential, and so is a corresponding library of data repair tools.

### 14.10.1 Inconsistencies Produced by Filter Differences

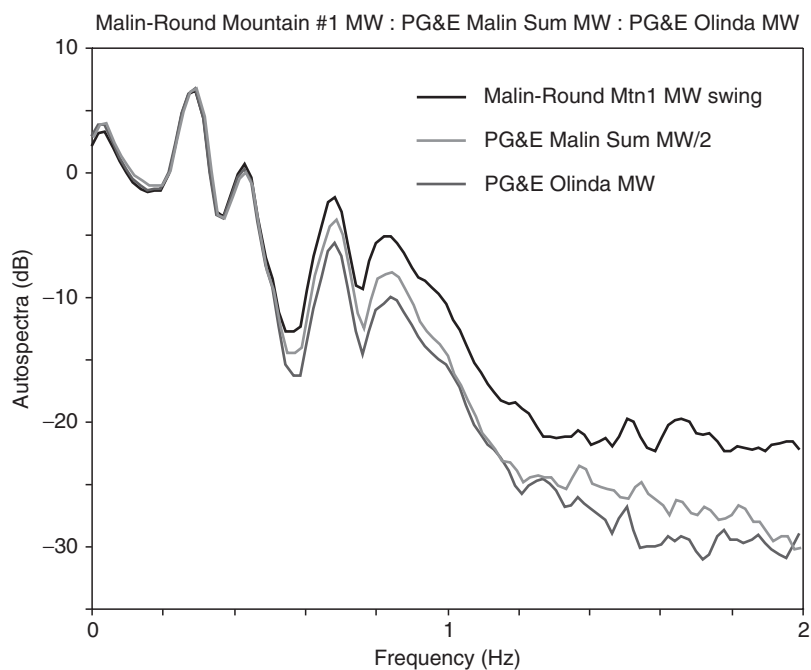
PMUs and other transducers produce RMS signals through some kind of averaging process involving or equivalent to a filter. The extent to which transducer filtering can “color” the view of power system transients is illustrated in Fig. 14.28. All signals are from the Malin area, near the Oregon–California border, and were recorded at BPAs Dittmer Control Center. Despite their obvious differences, all of the signals were obtained for essentially identical inputs to the various transducers. Except for fixed offsets (not shown) plus higher levels of measurement noise, the enhanced analog transducers on the Malin circuits produce signals that are closely consistent with each other and with the corresponding PMU signal. However, the signals produced by the standard transducers are somewhat different and both are seriously inconsistent with the other signals. They have lost their sharper features, and they have been delayed by roughly 400 ms. These are the effects of low-pass filtering, within the transducers themselves and possibly within the analog communication channels from Malin to Dittmer.

Within the context of their filtering the signals from the narrow bandwidth analog transducers are valid and useful. Figure 14.29, produced by spectral analysis under quiescent conditions, shows that all of the analog transducer signals contain the same basic information about dynamic activity. As briefly indicated in a later example, correlation analysis permits the filtering differences to be determined, modeled, and compensated when the need arises.

PMUs are not free of inconsistent filtering. The next section shows laboratory test results for this, and that the response of four specific PMUs would differ by  $\pm 15^\circ$  for a 1.4 Hz local mode oscillation.



**FIGURE 14.28** Malin area signals for NW generation trip event of April 18, 2002 (initial offsets removed).



**FIGURE 14.29** Ambient noise autospectra for Malin area transducers (1996).

There are many measurement applications in which such discrepancies would introduce unacceptable errors.

## 14.10.2 Timing Inconsistencies Produced as Pure Time Delays

Erroneous time delays among PMU signals have been encountered from the following sources:

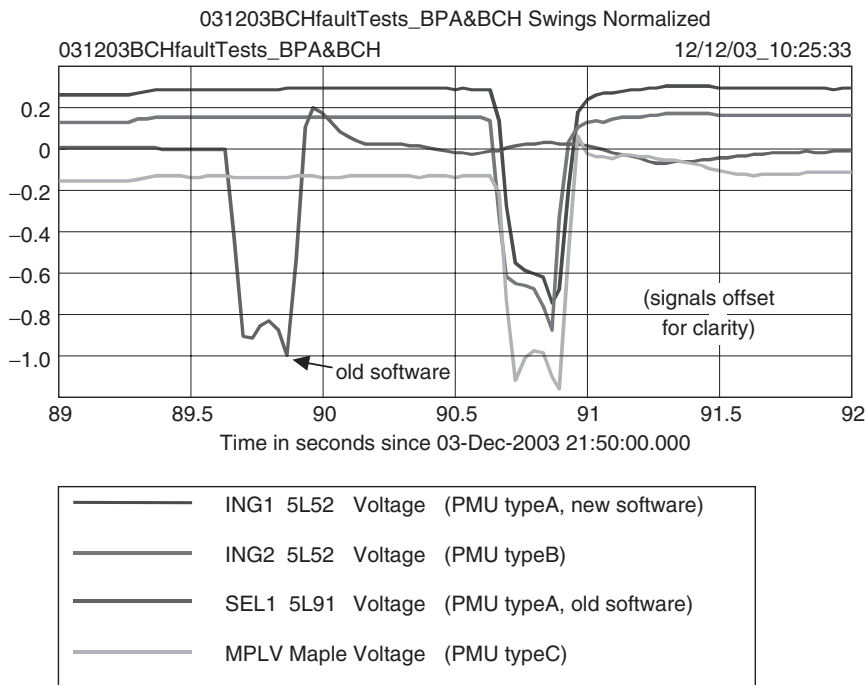
1. Time stamps that do not match the time at which the PMU output was produced
2. PMU frequency signals that are not time aligned with the phasor outputs
3. PMU outputs that were not produced at a standard time (the time stamps may be correct)

Important event data that are acquired before these problems are corrected must be either repaired or discarded.

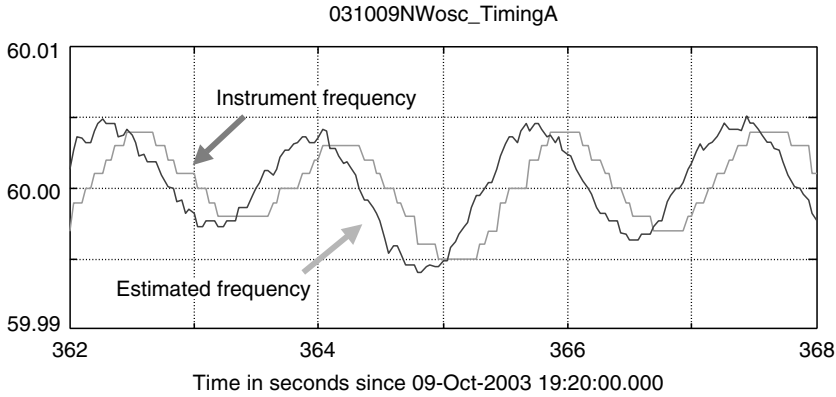
Examples of PMU timing errors are shown in Figs. 14.13 and 14.14 for fault tests performed at BCH. PMU MPLV is located at BPAs Maple Valley substation, near Seattle, Washington, and the remaining PMUs are located within the BCH system. PMU ING1 and PMU ING2, at Ingledow substation, share the same inputs but are of different types.

Earlier fault tests showed that the BCH signals were out of time with the BPA signal, and that no two of the BCH signals were timed consistently. This lack of timing consistency was partly because ING1 had just received a partial software update. Additional updates produced the much better timing shown in Fig. 14.30, though signals produced with older software were still out of time by about 1 s. An error of this sort is easily corrected by editing the time stamp for the entire PMU record, but one must know which PMU data to correct and by how much.

Figure 14.31 shows a case in which the PMU frequency signal is not time aligned with the phasor outputs. Correcting the data for this error is somewhat laborious, and estimating the size of the correction can be more so. This situation is fairly common, and a good countermeasure is to replace some or all instrument frequencies by estimated frequencies derived from bus angles.



**FIGURE 14.30** Relative timing of VMag signals BCH fault test on December 3, 2003.



**FIGURE 14.31** Timing anomaly in FreqL signal from ING1 PMU NW oscillation on October 9, 2003.

PMU outputs that were not produced at a standard time can produce major errors in bus angle. An example of this is mentioned in Ref. [33] but not shown. Resampling will repair such data, provided that the time stamps are correct.

### 14.10.3 Evaluation of PMU Performance

A PMU is both a network element and an RMS transducer. Evaluation of PMU performance is a complex matter that draws upon laboratory tests, model simulations, and comparative measurements under field-operating conditions [34,35].

Full evaluation of PMU performance must consider both its network performance, and its performance as an RMS transducer for steady state and dynamic information on the power system. All of these are major issues, and attention here is focused on dynamic performance only. Though the discussion is phrased in terms of PMUs, much of it applies to transducers and RMS calculations of other kinds.

RMS transducers provide average measures of point on wave input signals that represent local voltages and/or currents in the power system. The inputs can be thought of as sets of modulated carriers, containing dynamic information that is impressed through a combination of amplitude modulation and frequency modulation. The carrier frequencies are usually but not always harmonically related to the system-operating frequency. Transducer inputs occasionally contain additive components for which the frequencies are essentially arbitrary, and which probably have no direct association with generator activity [36].

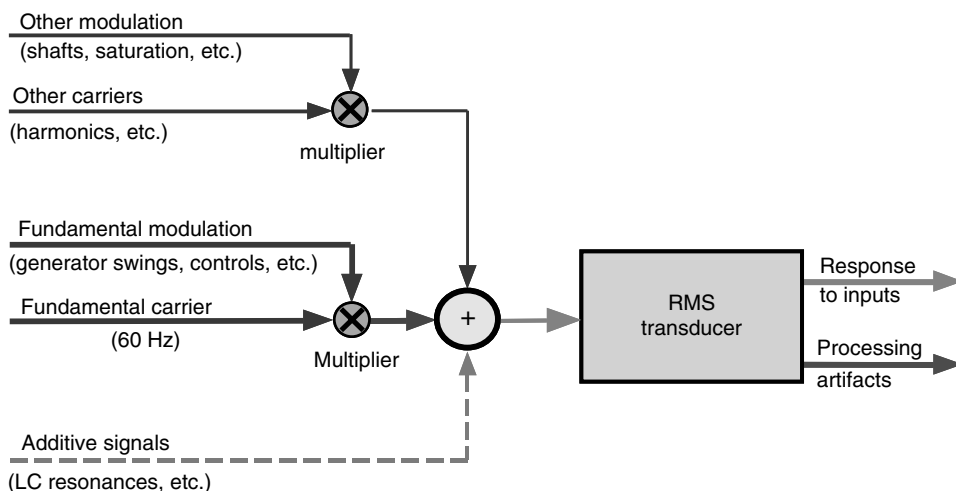
The overall situation is depicted in Fig. 14.32. It is useful to think of the carrier levels as *powerflow information*, and the impressed modulation as *dynamic information*. Additive signals, if present, are in a special category and potentially troublesome.

Amplitude modulation is the primary means by which dynamic information is impressed on the POW carriers. Such modulation produces sideband pairs according to the relation

$$\sin(x) \sin(y) = \frac{1}{2} [\cos(x - y) - \cos(x + y)] \quad (14.1)$$

e.g., if  $x$  represents a 60 Hz carrier frequency and  $y$  represents a 1.2 Hz modulation then the sidebands will be produced at  $60 \pm 1.2 = [58.8 \text{ } 61.2]$  Hz. Figure 14.33 provides an example with amplitude modulation sources at 1.05, 1.46, and 18.2 Hz. The example also includes an additive signal at 52 Hz, which is representative of a network resonance encountered during operation of the Celilo Damper.

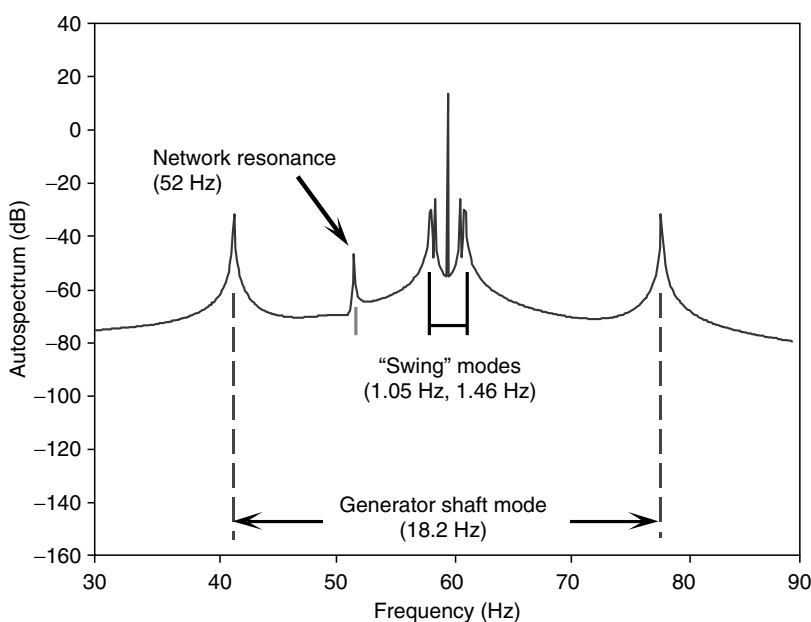
A useful first test under laboratory conditions is shown in Fig. 14.34, for a carrier frequency of 60.06 Hz and applied amplitude modulation frequencies in the sequence [0 0.28 1.4 6.64 12.0 15.0 21.72



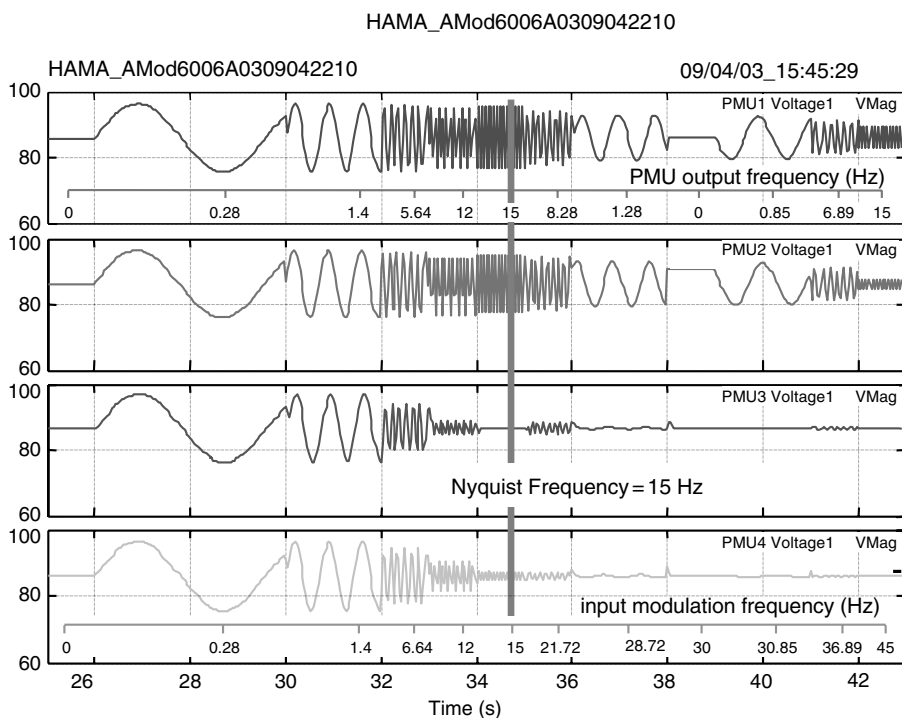
**FIGURE 14.32** Signal environment for a power system transducer.

28.7 30.0 30.85 36.89 45.0] Hz. The test signals for this are contained in a playback file (PMU\_AMod6006seriesA) for controlling voltage and current inputs to the PMUs, which were prototype units from commercial vendors.

The output rate for these instruments is 30 Hz, which can support no output frequency higher than the Nyquist frequency of  $30/2 = 15$  Hz. Response to inputs higher than this will necessarily be “aliased” to a lower frequency—e.g., a generator shaft oscillation at 21.72 Hz would produce an output at 1.28 Hz, and mimic a generator swing mode. The secondary axes in Fig. 14.34 show the relationship for this, and the overall figure shows that none of these instruments is fully protected against aliasing. This same information is implicit in the single frequency response scans of Fig. 14.35.



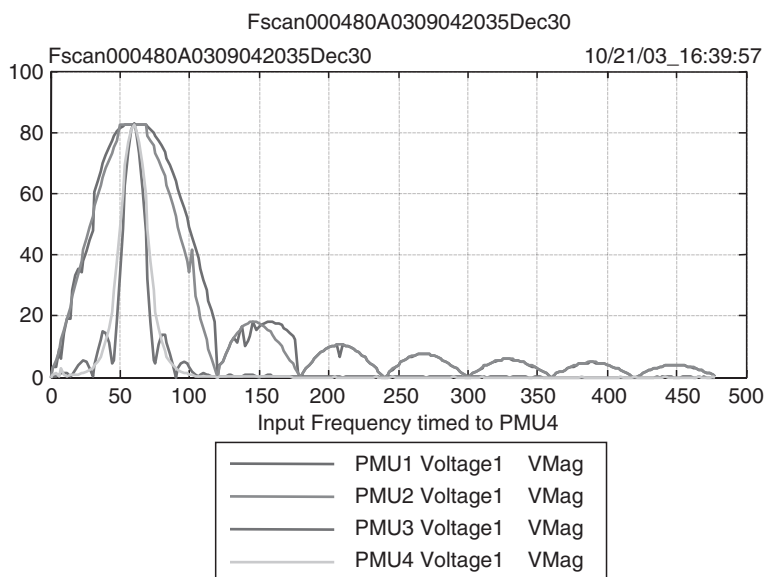
**FIGURE 14.33** Components of the information spectrum for an RMS transducer.



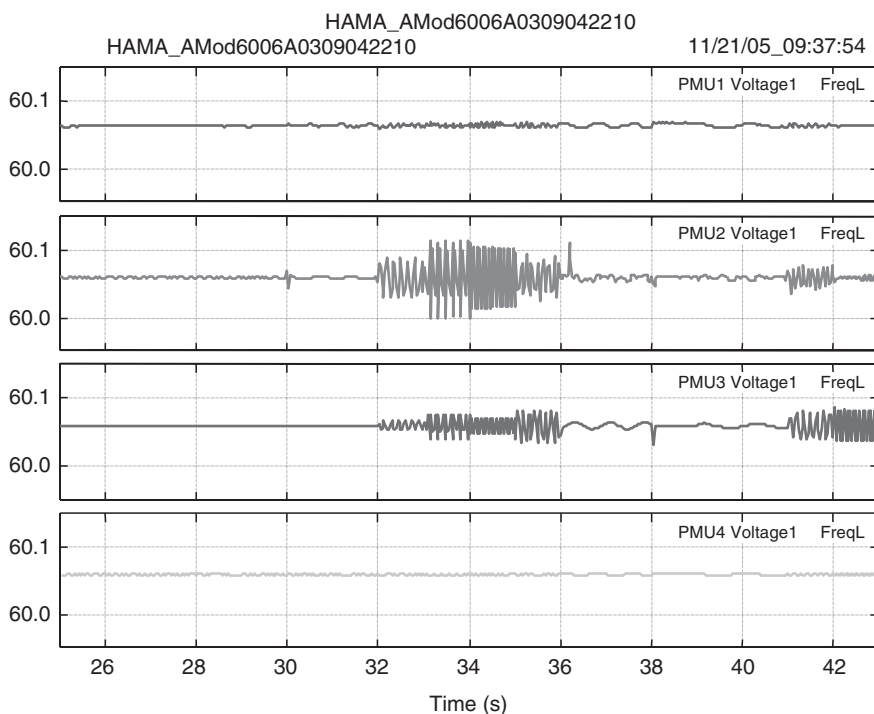
**FIGURE 14.34** Amplitude modulation scan of four PMUs (playback file AMod6006MseriesA).

Another class of problems is shown in Fig. 14.36, where amplitude modulation of some PMUs has produced spurious cross modulation of their frequency signals. This appears to be a result of asymmetric filtering in PMUs that do not compensate for off nominal system-operating frequencies.

Several other kinds of information can be extracted from the amplitude modulation scan. Examining PMU outputs across a time interval of zero modulation provides general indications of their relative



**FIGURE 14.35** Single frequency response scan of four PMUs (downsampled) (playback test file Fscan000480A).



**FIGURE 14.36** Spurious cross modulation of PMU frequency outputs (playback file AMod6006MseriesA).

accuracy, offsets, and noise characteristics. Relative timing, gain, and waveform distortion can be determined very accurately through Prony analysis of PMU response to the lower modulation frequencies (e.g., up to perhaps half the Nyquist frequency).

Table 14.3 indicates that the voltage output from PMU3 is about 34 ms later than that from PMU4, and some 55 ms later than that from PMU2. Mode shape analysis, if based upon this collection of PMUs, would have an uncertainty of  $\pm 14^\circ$  for a 1.4 Hz local mode oscillation. These output discrepancies exist even though the instruments, nominally at least, are synchronized within a few microseconds at their inputs. Evolving filter standards in the IEEE synchrophasor standard [37] address such problems.

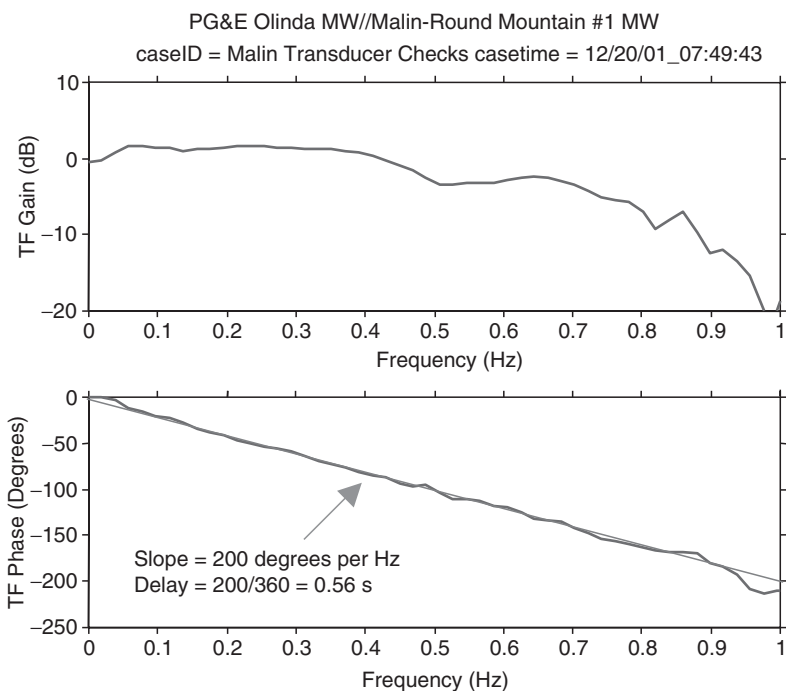
#### 14.10.4 Need for Reference Signals

Calling signals consistent implies that there is some standard of comparison. Once an instrument is placed in field operation it is rarely possible to test it directly. Its performance must then be judged by comparisons against other signals of assumed or proven quality.

The overlapping monitor coverage at Malin is a case in point. The high-quality analog signals from Malin are directly valuable for the dynamic information they provide about power system behavior, and

**TABLE 14.3** Relative Timing of Four PMUs (Playback File AMod6006MseriesA, 1.40 Hz)

| Sorted PRS Table for Pole1: Interarea Oscillation: TRange = [5.4667 7.0] + 24.8 s |                |                 |           |            |                 |
|-----------------------------------------------------------------------------------|----------------|-----------------|-----------|------------|-----------------|
| Signal                                                                            | Frequency (Hz) | Damp Ratio (pu) | Res. Mag. | Res. Angle | Rel. Delay (ms) |
| PMU1 VMag                                                                         | 1.40003246     | 0.00004210      | 10.3309   | 160.562    | 8.7             |
| PMU2 VMag                                                                         | 1.40003246     | 0.00004210      | 10.3400   | 175.578    | −21.1           |
| PMU3 VMag                                                                         | 1.40003246     | 0.00004210      | 10.2610   | 147.745    | 34.2            |
| PMU4 VMag                                                                         | 1.40003246     | 0.00004210      | 10.2632   | 164.957    | 0.0             |



**FIGURE 14.37** Virtual frequency response of PG&E Olinda MW to Malin-Round Mountain #1 MW.

they provide a useful check on the corresponding PMU signals. In addition to this, the high bandwidth signals of both kinds display sharp features from which timing information can be established when clock-based time stamps are suspect or absent. The high bandwidth signals provide a basis for modeling and compensating filter effects in more sluggish transducers [32]. A brief example of this is shown in Fig. 14.37, where correlation of ambient noise signals has provided a virtual transfer function from the Malin-Round Mountain signal to the PG&E-Olinda signal (shown as PG&E Captain Jack MW in Fig. 14.28). Through these secondary contributions the high-quality analog signals enhance the overall value of the legacy analog system, and they provide a means by which the more heavily filtered signals can be interpreted properly.

## 14.11 Monitor System Functionalities

The measurement of low-level interactions sets the quality requirements for measurement of WAMS data [26]. However, it is the real-time evaluation of system dynamic performance that sets the quality requirements for the display and analysis of the data. This is particularly critical during staged tests, when a close balance must be maintained between system security and the quality of test results. It is also important during routine monitor operations, as a means for identifying important data and for generation of operator alerts.

Functions for this are the following:

- *Signal conditioning and data repair*, to assure the measurement quality and prompt observability of important signal features.
- *Archival recording*, to assure safekeeping of important results. This should be as comprehensive as possible, and include all phases of testing that involve switching operations or application of test signals.



- *Interactive recording*, to permit prompt examination of data that cannot be fully assessed in real time. This also provides backup recording of high priority signals.
- *Time-domain display*, to permit frequent review of signal waveforms for evidence of data quality and emerging trouble on the power system.
- *Frequency-domain display*, to permit frequent review of signal spectra for evidence of data quality and possible trouble on the power system.

Some of the analysis tools underlying these displays are also used in event detection logic (EDL) to trigger automatic functions such as accessory data capture, information routing, or operator alerts.

Not all monitors are interaction monitors, and many interaction monitors lack some of the functions shown. The required functionality resides in the overall measurement system. The power system contains many devices that can serve as monitors for some processes and purposes. For the purposes at hand the following definition is appropriate:

*A monitor is any device that automatically records power system data, either selectively or continuously, according to some mechanism that permits the data to be retrieved later for analysis and display.*

The usual disturbance monitor is a snapshot recorder that captures local data for disturbances that are strongly observable in the monitor inputs. A circulating prehistory buffer retains the most recently acquired data, assuring that a certain amount of information will be provided about system conditions before the disturbance is detected.

WECC experience indicates that triggered data capture does not provide an adequate basis for wide area measurements. Even rather large events may not be sensed by trigger logic that is remote from the site of the disturbance. Records for a cascading failure that develops slowly, from some fairly small initiating event, are unlikely to present a comprehensive view of the mechanism by which the small failure propagated into a very large one.

Figure 14.3, in an earlier section, illustrates the point. The record there, collected on BPAs earlier Power System Disturbance Monitor, indicates peak-to-peak 0.7 Hz swings of roughly 900 MW on the PACI. It failed to capture the all-important interval during which the oscillations started. Without this, whatever indications there may have been to warn system operators of pending trouble remain unknown.

Monitors that are explicitly designed to operate in a continuous recording mode are more reliable, and usually require less staff attention. Present technology readily supports “stream to archive” monitors that will maintain a continuous data record for periods ranging to several weeks.

## 14.12 Event Detection Logic

There are four basic factors involved in detecting the onset of a dynamic event. They are *magnitude*, *persistence*, *frequency content*, and *context*. A simple disturbance trigger might examine just magnitude and persistence, in tests of form *Do the latest M samples each exceed threshold T(M)?* [38]. It is useful to think of the context factor as adjusting such thresholds to system conditions, such as network stress or the operational status of key system resources.

Data signatures through which events can be detected, and perhaps recognized, include the following:

- Steps or swings in tieline power
- Large change, or rate of change, in bus voltage or frequency
- Sustained or poorly damped oscillations, perhaps in conjunction with some other event
- Large increase in system noise level
- Increase of system activity in some critical frequency band
- Unusual correlation or phasing between fluctuations in two given signals

The tools needed to extract useful signature information from measured data range from straightforward heuristics to very advanced methods of signal analysis. Recognition of the underlying events calls for pattern recognition logic to match extracted signatures against known event templates.

## 14.13 Monitor Architectures

A fully evolved monitor system for main grid performance must provide the following services:

- *Comprehensive recording of operating data*, in secure archives that are promptly accessible for grid management
- *Analytical displays of system behavior*, using time- and frequency-domain tools to highlight critical aspects of system behavior
- *Automatic detection of unusual conditions or activity*, producing operator alerts and cross-trigger commands to secondary recording systems

Providing these services implies an integrated set of processing functionalities equivalent to that in Fig. 14.38. In a full-scale WAMS these may be distributed across many devices and replicated in many places. This is especially true of the archiving and display functionalities. Linkages to the energy management system (EMS) are likely.

The indicated triggers are both external and internal, manual and automatic. The internal automatic triggers are classified as short or long (fast or slow), depending upon length of the data segment needed by the associated EDL. Short EDL can work with a short block of recent data, and is usually sufficient for disturbance monitoring.

A distinguishing feature in this architecture is the signal-processing buffer (SPB) used for advanced triggers (in the long EDL) and in special displays. SPB functionality is essential for extracting interaction signatures, and for presenting those signatures to operations staff for their interpretation and review. At hardware level, however, this functionality can be distributed among one or more buffers internal to the monitor itself plus external buffers for shared access to the record stream at file level.

A next step in monitor refinement is to enhance the EDL and trigger coordination functions of Fig. 14.38 through artificial intelligence. Figure 14.39 represents a dynamic event scanner (DES) suitable for this purpose, and for an Archive Scanner to review central data collections.

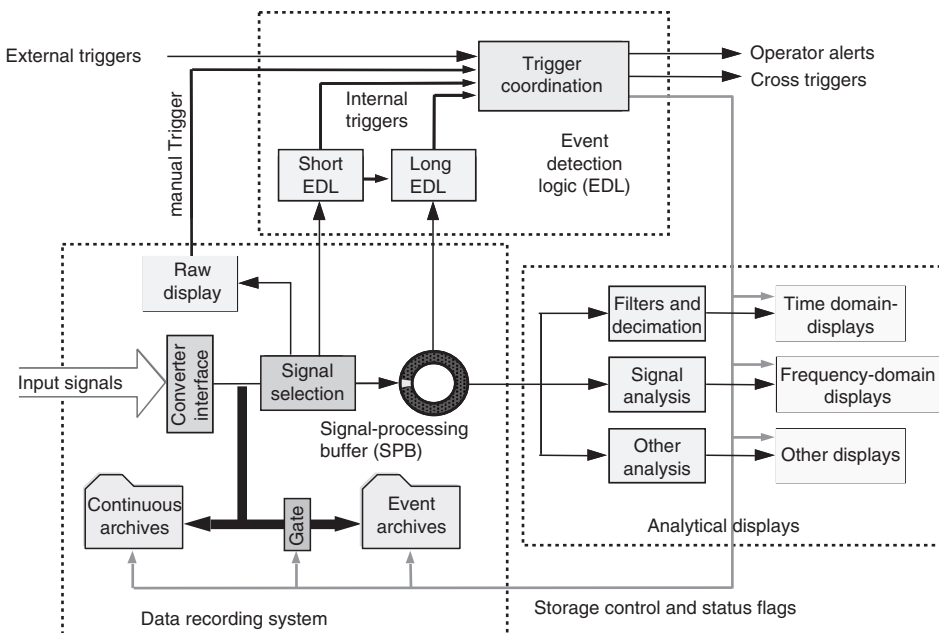


FIGURE 14.38 Processing functionalities in a fully evolved power system performance monitor.

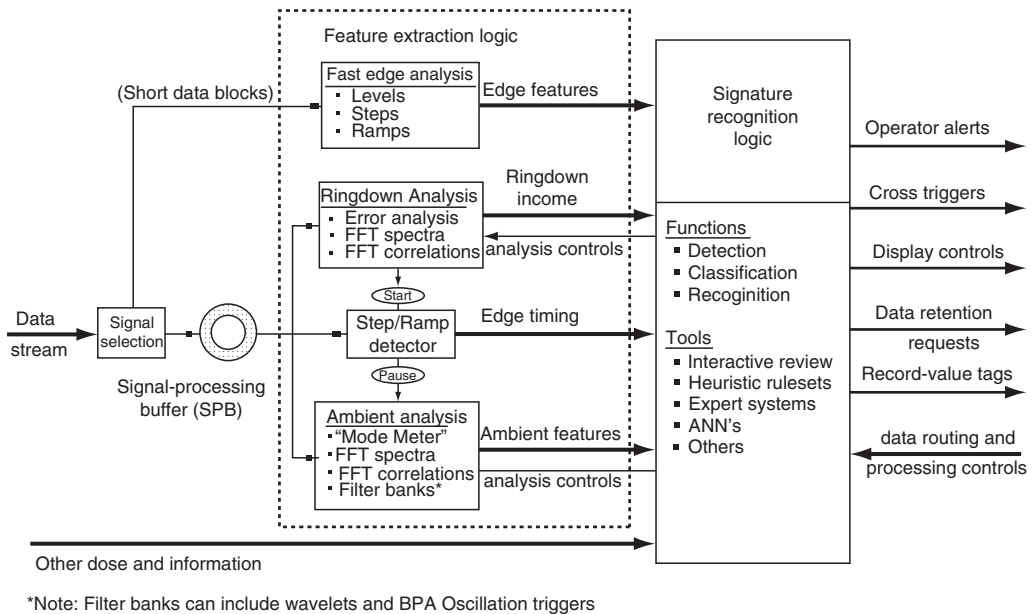


FIGURE 14.39 Dynamic event scanner within a continuous monitor.

## 14.14 Organization and Management of WAMS Data

A major test or disturbance on a large power system produces literally thousands of data objects in the form of raw or processed measurements, modeling results, message traffic, staff activity logs, and reports. In many cases the signals derived from measurements are analyzed in parallel with equivalent signals that have been obtained from computer simulations.

The WAMS database for a major event on the power system may be far larger than that for regular system operation. The analysis itself is usually much more thorough, and it usually produces a greater number of analysis products. Also, as insight into the event evolves, the analysis will often extend to secondary data that are not usually examined. It is necessary to smoothly manage the database as it expands, and to do so in a manner that observes confidentiality agreements among data owners or system managers.

Organization of the WAMS database relies upon

- A *standard dictionary* for naming power system signals
- A *summary processing log* indicating where the signals originated and how they have been processed
- *Data management conventions* that name and store the data objects according to the system event

This aspect of WECC practice is built into “workflow” patterns that have evolved among WAMS facility owners and various WECC technical groups. Some parts of it have been automated into the DSI toolbox, which is the standard WECC tool for WAMS analysis.

Other parts are incorporated into WAMS operation, or into the measurement system itself. One of these is the data source *configuration file*, which provides information for the following purposes:

- *Converting raw data to engineering units*, includes initial corrections to known offsets in the data.
- *Automatically naming of extracted signals*, includes renaming to control information concerning data sources and ownership.
- *Logging of data source characteristics*, links to data servicing tools for repair, adjustment, or other modifications that may be required immediately or at some future time.
- *Standardizing naming of the data source*, links to dictionaries that contain processing menus that have been customized for specific users and/or operating environments.

The same measurements that system operators see in real time may contain benchmark performance information that is valuable for years into the future. Such measurements may also be needed to

determine the sequence of events for a complex disturbance, to construct an operating case model for the disturbance, or as a basis of comparison to evaluate the realism of power system models in general.

These observations imply two general rules for the organization of WAMS data:

*Rule #1.* WAMS data must remain retrievable and useable for many years after acquisition.

*Rule #2.* Procedures and toolsets for analysis of the WAMS database must be applicable to simulated measurements produced by model studies.

The above two rules are actually basic requirements from which many other rules, practices, or guidelines can be derived. For example, from Rule #1 we can derive the following:

*Rule #3.* Any WAMS data or analysis product must be clearly tagged to indicate—the origin of the data

- The conditions under which the data were acquired
- The processing applied to the data

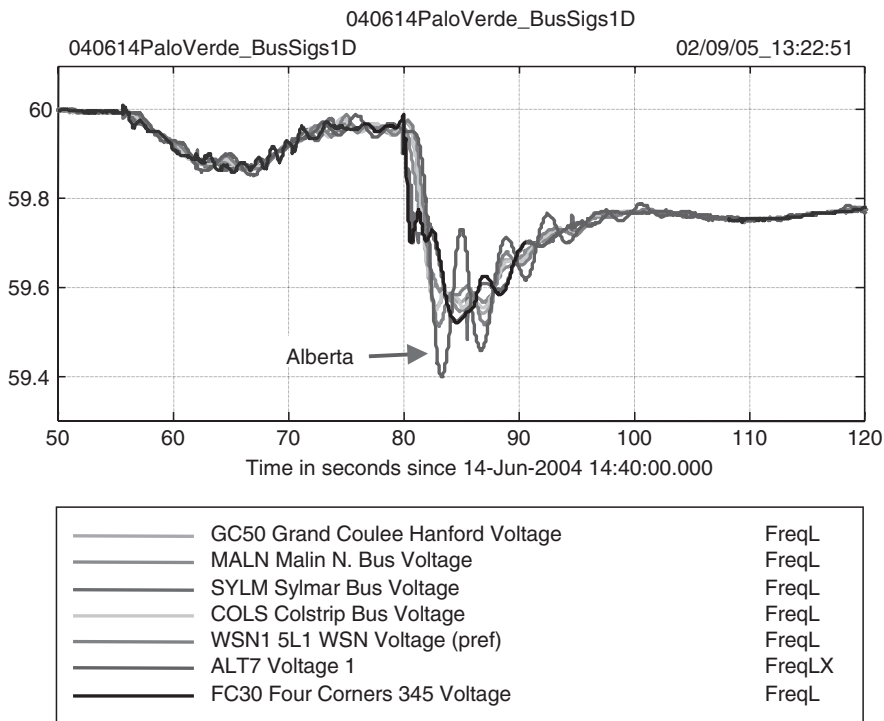
And, expanding upon Rule #2, for any large power system we have

*Rule #4.* Procedures and toolsets for analysis of the WAMS database must permit integrated analysis of

- Measured power system behavior as obtained from any recorder in general use
- Simulated power system behavior as obtained from any modeling program in general use

Application of these rules is demonstrated in Fig. 14.40, for a disturbance near Phoenix Arizona on June 14, 2004. The resulting frequency transients are shown for locations that range from western Canada to southern California and Arizona. The figure provides the following general information:

- It was produced by a processing case called 040614PaloVerde\_BusSigs1D
- The processing case was initiated at a local time of 02/09/05\_13:22:51



**FIGURE 14.40** WECC Event June 14, 2004: Overview of PMU frequency signals.

- All signals are of type *FreqL* and thus local frequencies. The specific names indicate the sources as PMUs.
- The X in *FreqLX* for ALT7 in Alberta Canada indicates that the associated PMU had probably lost its GPS synchronization.

The name of the processing case, shown in the figure, indicates parent data files in the WAMS database at PNNL. Farther details of this example are provided in Refs. [39,40].

## 14.15 Mathematical Tools for Event Analysis

Figure 14.41 is a paradigm for the tools and procedures used in WAMS analysis. Modeling is a major topic in its own right, and not pursued here. The eigenanalysis derived from model data is closely linked to signal analysis, however, and some basic notions are needed here.

Modal analysis of oscillatory dynamics builds upon a tentative assumption that the dynamics are essentially linear for small motions about the equilibrium state. To the extent that this assumption is valid, the “swings” following a brief disturbance will be a sum of modal response terms like

$$m(t) = M \exp(-\sigma t) \cos(\omega t + \theta) \quad (14.2)$$

Here  $(\sigma, \omega)$  are *mode parameters* that denote the frequency and damping of a mode, and  $(M, \theta)$  are *mode shape parameters* that denote the strength and phase of that mode within signal  $m(t)$ . Mathematically, the mode parameters are expressed as a complex *eigenvalue*  $\lambda = \sigma + j\omega$  and the mode shape parameters are expressed as a *residue*.

Underlying Eq. (14.2) are the system equations  $\dot{x} = Ax + Bu$  and  $y = Cx + Du$ , where  $\dot{x}$  denotes differentiation of  $x$  with respect to time. Variables  $u$  and  $y$  are respectively the *input* and the *output* of the system;  $x$ , the *internal state* of the system, is usually taken to be a vector of  $n$  elements.

Full eigenanalysis is based upon modal decompositions of the  $A$  matrix, which in turn requires a source model from which to extract it [8]. This produces a full set of eigenvalues plus associated eigenvectors. The eigenvalues lead to residue matrices with mode shape information that is specific to very special kinds of inputs and outputs.

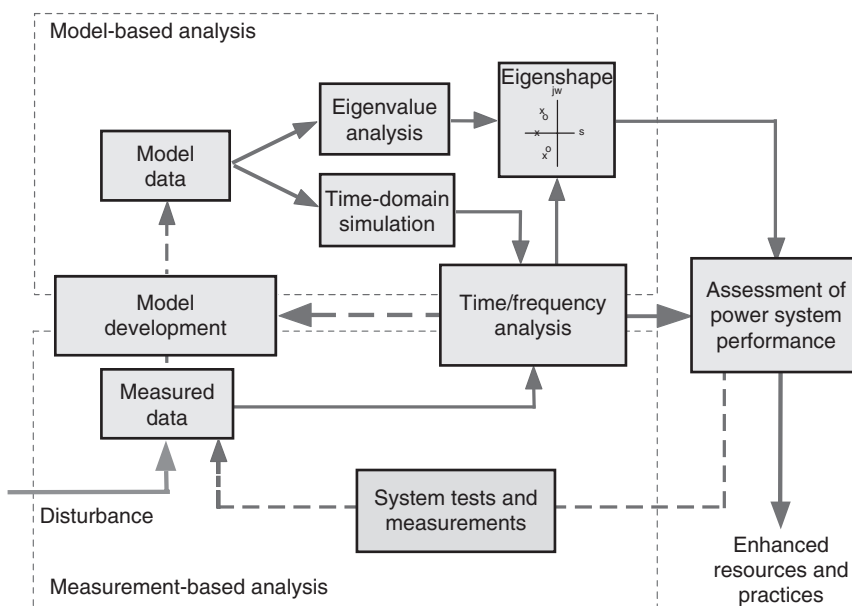


FIGURE 14.41 Integrated use of measurement and modeling tools.

Prony analysis, by contrast, is based upon modal decompositions of output vector  $y(t)$ . The modes and the modal parameters are those for a subset of  $A$  that is estimated from a subset of  $y(t)$ ; the mode shape parameters are specific to whatever stimulus may have produced the output. Given sufficient knowledge of  $u(t)$ , an approximating subset can be constructed for  $\{A, B, C, D\}$  [41,42].

In practice  $u(t)$  is usually a sequence of discrete switching events that are not immediately known. Small signal analysis assumes that the response to each event is a free ring down of form

$$x(t) = \sum_{i=1}^n R^{(i)} x_0 \exp(\lambda_i t) \quad (14.3)$$

where  $R^{(i)}$  is a residue matrix and state  $x_0$  is the deviation from final equilibrium. Most events will redefine  $x_0$ , and some events or discrete control actions may significantly alter the underlying system parameters. Hence proper analysis must proceed on a piecewise basis.

All of these methods are approximate, and none can generate results of higher quality than the information provided to them. Results from model-based eigenanalysis are colored by errors in the model, and by linear approximations to nonlinear phenomena such as saturation and dead zones. Results from measurement-based eigenanalysis are colored by the extent and quality of the available signals. Some modes may not be sufficiently observable within the signal set. Those which are observable may be obscured by noise, by dynamic nonlinearities, and by hidden inputs to the system.

Prony analysis, in the present context, is considered to include any algorithm that directly fits time-domain signals with the “Prony model” of Eq. (14.2). This model generalizes that of Fourier analysis, and can sometimes be used for the same purposes. Fourier methods remain a mainstay of WAMS analysis, however [43]. Examples of such analysis are provided below.

### 14.15.1 Western System Breakup of August 10, 1996

Comprehensive data for the August 10 breakup were captured on a PPSM unit at BPAs Dittmer Control Center, which was recording continuously at 20 sps. The existing archive extends from 0951 to 1154 PDT, and then from 1258 to 1603 PDT. Key portions of the overall record are shown in Figs. 14.5, 14.12, 14.42, and 14.43. Tripping of McNary generation was a major factor in the breakup.

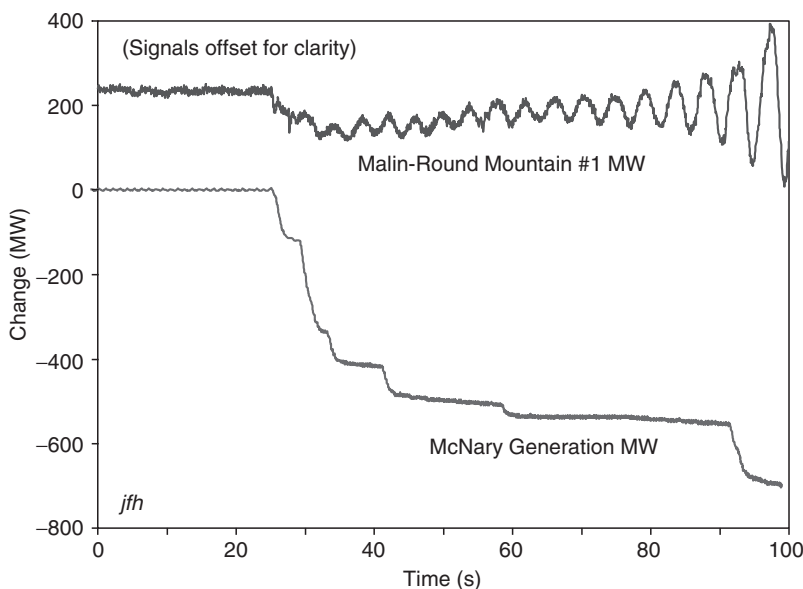
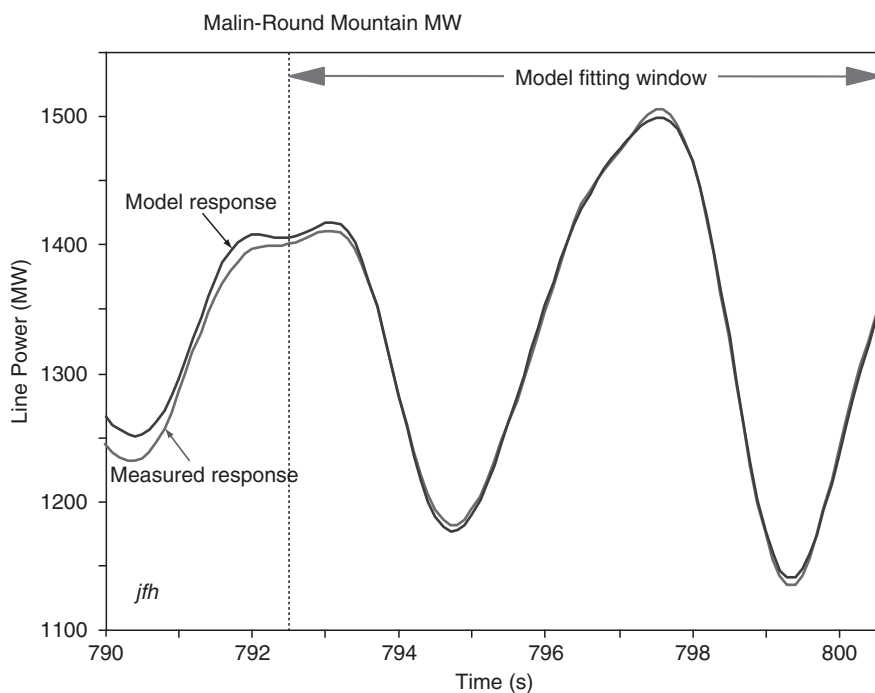


FIGURE 14.42 McNary plant generation during WSCC breakup of August 10, 1996.



Prony Model Table

| Mode         | Frequency (Hz) | Damping Ratio |
|--------------|----------------|---------------|
| PACI         | 0.216          | −0.0628       |
| signal trend | 0.0596         | −0.0216       |
| Alberta      | 0.448          | −0.0234       |
| Kemano       | 0.615          | −0.0234       |

**FIGURE 14.43** Oscillation modes just prior to final separation on August 10, 1996.

Tables 14.4 and 14.5 show that frequency and damping of the PACI mode were normal in the morning of August 10, but lower than normal after the John Day–Marion line trip. Though the system (and mode frequency) recovered, this event may have been a near miss [9]. Though the Keeler–Allston line trip produced a similar drop in mode parameters, it occurred under weaker conditions leading to

**TABLE 14.4** Behavior of the PACI Mode to August 10, 1996

| Date/Event                 | Frequency (Hz) | Damping (%) |
|----------------------------|----------------|-------------|
| 12/08/92 (Palo Verde trip) | 0.28           | 7.5         |
| 03/14/93 (Palo Verde trip) | 0.33           | 4.5         |
| 07/11/95 (Brake insertion) | 0.28           | 10.6        |
| 07/02/96 (System breakup)  | 0.22           | 1.2         |

**TABLE 14.5** Behavior of the PACI Mode on August 10, 1996

| Time/Event                    | Frequency (Hz) | Damping (%) |
|-------------------------------|----------------|-------------|
| 10:52:19 (Brake insertion)    | 0.285          | 8.4         |
| 14:52:37 (John Day–Marion)    | 0.264          | 3.7         |
| 15:18 (Ringing)               | 0.276          |             |
| 15:42:03 (Keeler–Allston)     | 0.264          | 3.5         |
| 15:45 (Ringing)               | 0.252          |             |
| 15:47:40 (Oscillation start)  | 0.238          | −3.1        |
| 15:48:50 (Oscillation finish) | 0.216          | −6.3        |

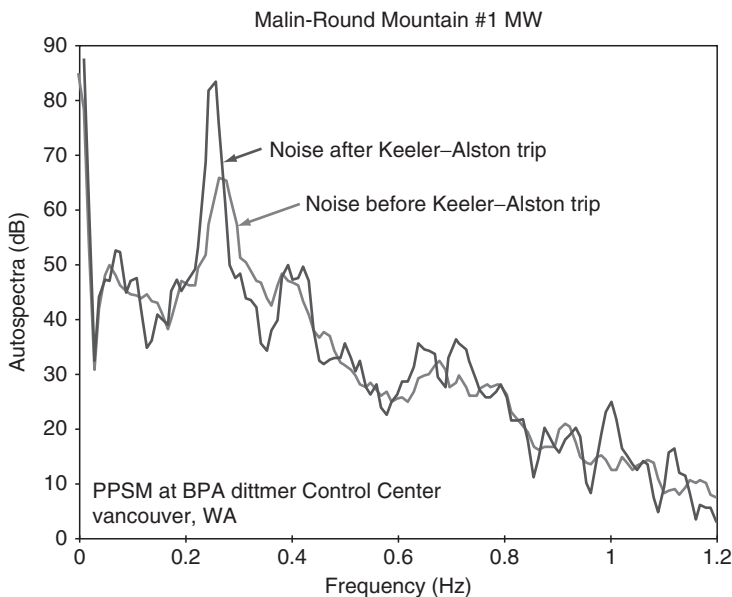
successive generator trips and increasingly violent oscillations [11,13,44]. By that time the only way to mitigate them would have been to cut the interaction paths by islanding the system.

Much of this information is readily apparent to Fourier analysis. Figure 14.44 shows spectral changes produced by the Keeler–Allston line trip, and Fig. 14.6 shows evolving spectra for the final minutes before the breakup time/frequency displays of this sort are easily implemented and highly recommended.

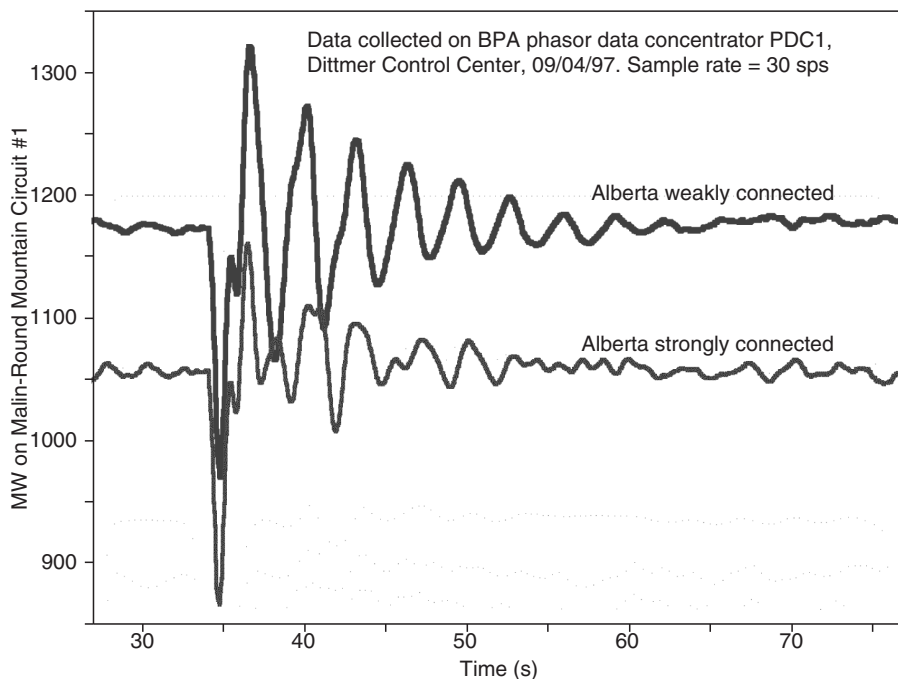
### 14.15.2 Effects of the Alberta Connection

The Alberta power system, with a capacity of roughly 10,000 MW, is usually connected to the remainder of the western power system through a 500 kV tie plus two much weaker lines. However, it is not unusual for the Alberta system to operate as an island for days at a time.

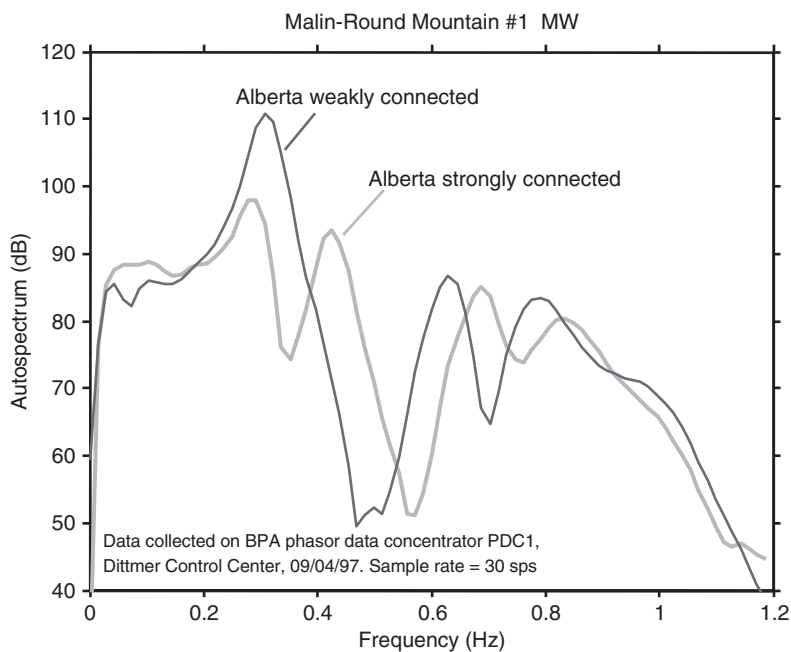
Operational status of the 500 kV Alberta connection defines two distinct patterns for modes in the overall power system. Typical effects are shown in Figs. 14.45 and 14.46, and in Table 14.6 [16]. Model studies must consider both of these, and the settings for some kinds of stability controls would have to be “scheduled” differently for each condition. This is especially likely for wide area damping controls based on modulation of HVDC, TCSC, or SVC equipment.

**FIGURE 14.44** Spectra for Keeler–Alston line trip just before WSCC breakup.





**FIGURE 14.45** Effects of the Alberta connection: COI response to energization of the 1400 MW Chief Joseph dynamic brake.



**FIGURE 14.46** Effects of the Alberta connection: COI response to energization of the 1400 MW Chief Joseph dynamic brake.

**TABLE 14.6** Effects of the Alberta Connection on WECC Modes

| Mode        | Alberta Strongly Connected | Alberta Weakly Connected |
|-------------|----------------------------|--------------------------|
| North–South | 0.296 Hz at 4.9%           | 0.314 Hz at 5.7%         |
| Alberta     | 0.424 Hz at 4.3%           |                          |
| Kemano      | 0.637 Hz at 5.1%           |                          |
| Kemano?     | 0.703 Hz at 7.5%           |                          |
| Colstrip    | 0.751 Hz at 8.5%           | 0.751 Hz at 6.8%         |

### 14.15.3 Model Validation against WSCC Tests on June 7, 2000

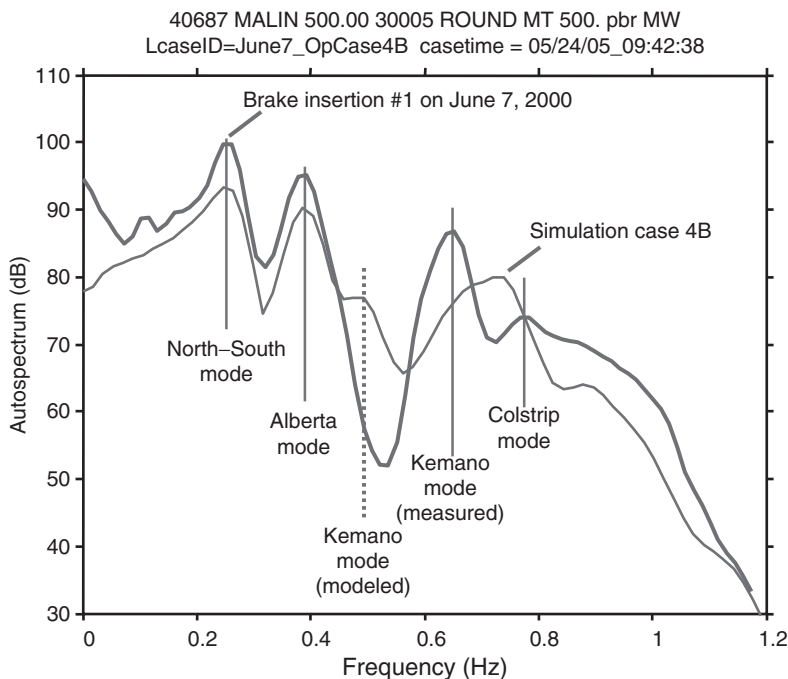
On June 7, 2000, the WSCC performed a series of benchmark tests to examine system dynamic performance with the Alberta system strongly connected [45,46]. One product of the tests was a series of planning models calibrated against measured response.

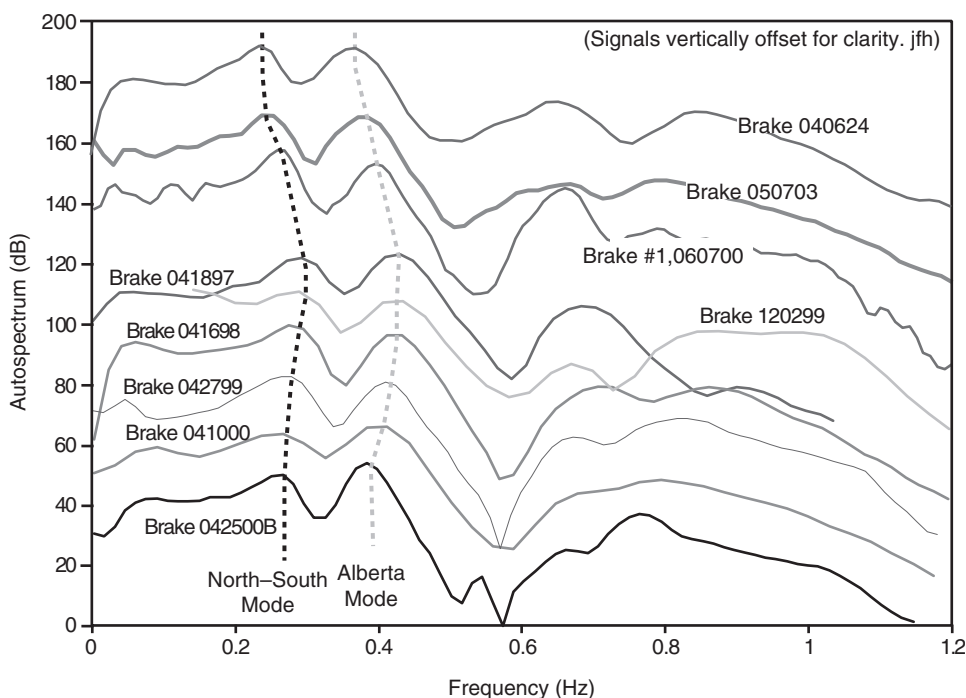
Figure 14.47 presents a frequency-domain view of comparative model response for insertion of the Chief Joseph dynamic brake. The model is outwardly realistic for the North–South mode and for the Alberta mode. An immediate question is whether its representation of the Kemano mode is within the normal range of system behavior, and thus marginally acceptable.

Such questions require comparisons against historical records. Figure 14.48, for brake insertions between 1997 and 2004, show that this modeling of the Kemano mode is either unrealistic or very atypical. Actual frequency of the Kemano mode can also be determined by spectral analysis of ambient noise and transient disturbances recorded in the BCH system.

### 14.15.4 ACDC Interaction Tests in September 2005

On September 13 and 14, 2005 the BPA performed comprehensive probing tests extending those of June 7, 2000. These tests were performed in coordination with WECC technical groups, following an official Test Plan [47] and general guidelines presented in Ref. [48].

**FIGURE 14.47** Brake insertion #1 on June 7, 2000 (Alberta strongly connected).



**FIGURE 14.48** Ringdown signatures for recent insertions of the Chief Joseph dynamic brake (Alberta strongly connected).

The test objectives included the following:

- A. Obtain a seasonal benchmark for dynamic performance of the WECC system
- B. Develop comparative data to evaluate and refine the realism of WECC modeling tools
- C. Refine and validate methods that identify power system dynamics with minimal or no use of probing signals

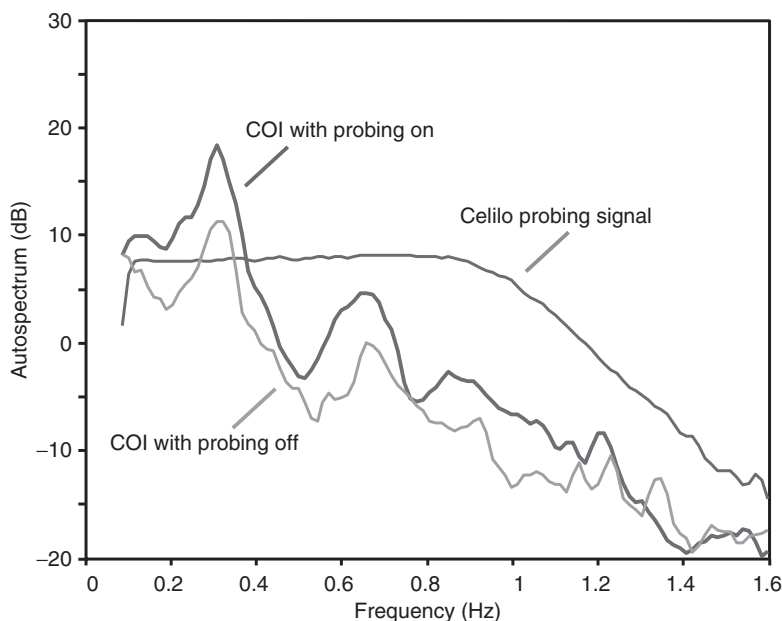
Distinguishing features of the June 2005 tests were a strong focus on objective C, plus greatly improved instrumentation and software for achieving this objective. This section shows initial results obtained for probing with low-level pseudorandom noise, and the Alberta system disconnected from the remainder of the grid (Fig. 14.49).

The basic strategy in low-level probing is to start with a very weak probing signal, and to progressively adjust that signal to the minimum level that produces acceptable results. Key real-time resources for this are PDC StreamReaders, accompanied by an add-on dynamic signal analyzer (DSA) tool for spectral analysis (shown earlier in Fig. 14.10). Off-line tools for full analysis include SYSFIT [49], for transfer function fitting, plus a range of advanced tools that are applied in time domain [50–52].

Results shown in Figs. 14.50 through 14.52 were obtained with band-limited white noise having limits of  $\pm 20$  MW dc and a standard deviation of 14 MW. These indicate that good measurements can be obtained with a probing signal that roughly doubles the apparent noise that is natural to the power system, and is essentially invisible to all but the closest examination.

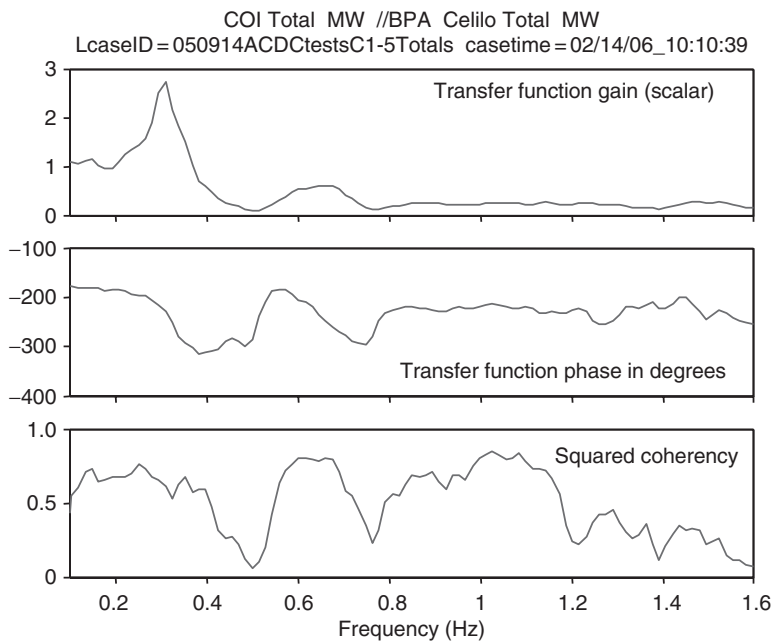
## 14.16 Conclusions

Extracting useful information from power system behavior requires integrated use of measurements, models, and mathematics in a collaborative effort of many entities. SSM networks, of which PMU networks are a salient example, provide the enabling platform for the infrastructure.

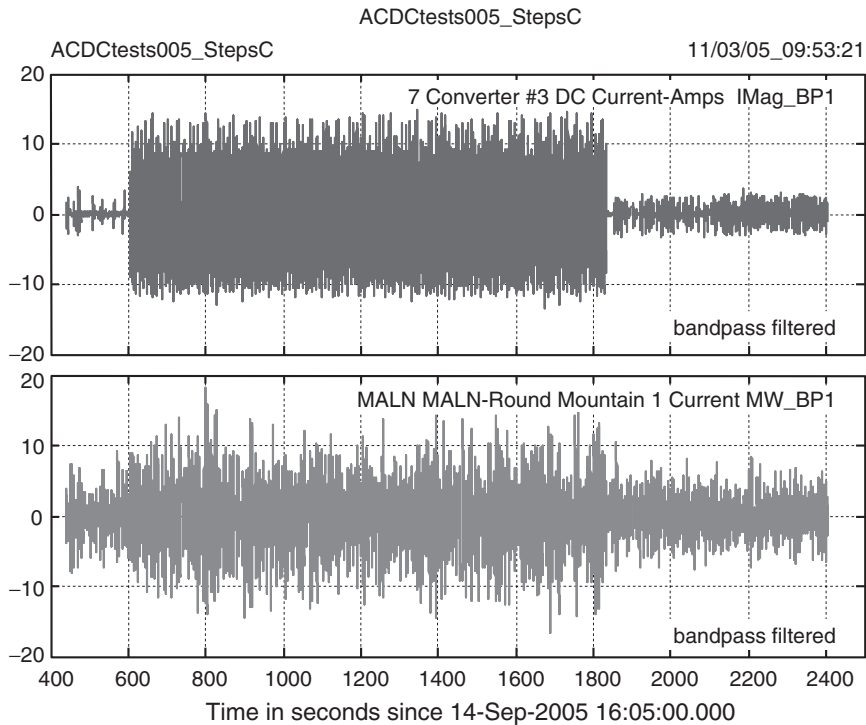


**FIGURE 14.49** Autospectra for low-level noise probing.

PMUs are an important and representative aspect of the ongoing transition from analog technology to digital technology. They offer the promise of standardized measurements that greatly improve upon the quality of their analog predecessors, and of information networks that provide detailed real-time portraits of entire power systems. And, like most digital technology, they are undergoing significant

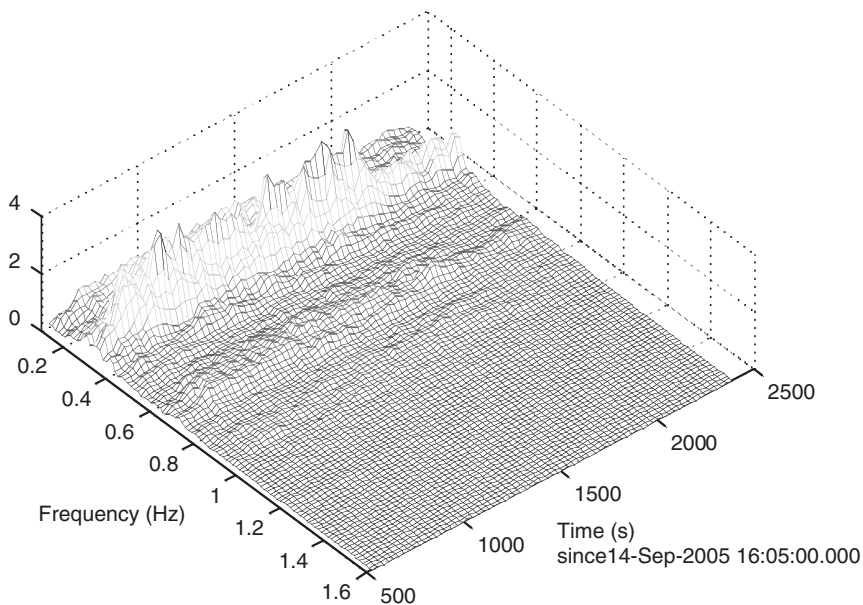


**FIGURE 14.50** Correlation results for low-level noise probing.



**FIGURE 14.51** Response of Malin-Round Mountain MW to low-level noise probing.

evolutionary changes after being placed in service. Basic issues to be resolved are the operating environment in which the technology must perform, the information functions that it must support, and how that information enters the grid management process.



**FIGURE 14.52** Response of Malin-Round Mountain MW to low-level noise probing.

Given a sharper perspective on these matters, the community of technology users can join with that of technology developers to better define the performance expected of SSM technologies, and to develop suitable means for determining the degree to which a particular instrument has met those expectations. Resolving these issues for PMU technology provides the basis for a future common standard that is applicable to all devices which export phasor signals (including some digital relays and controllers), and that can be extended to multirate SSM networks that are not restricted to phasor signals.

## Glossary of Terms

---

|       |                                                            |
|-------|------------------------------------------------------------|
| DSA   | dynamic signal analyzer                                    |
| DSM   | dynamic system monitor                                     |
| GPS   | global positioning satellite                               |
| IMU   | information management unit                                |
| PDC   | phasor data concentrator                                   |
| PMU   | phasor measurement unit                                    |
| PPSM  | portable power system monitor                              |
| PSM   | power system monitor (primary definition)                  |
| PSM   | power system measurements (secondary definition)           |
| SCADA | supervision control and data acquisition                   |
| SPM   | synchronized phasor measurements                           |
| SSM   | synchronized system measurements                           |
| AGC   | automatic generation control                               |
| FACTS | flexible AC transmission system                            |
| HVDC  | high-voltage direct current                                |
| PSS   | power system stabilizer                                    |
| SVC   | static VAR compensator                                     |
| TCSC  | thyristor-controlled series capacitor                      |
| EIPP  | Eastern Interconnection Phasor Project                     |
| WACS  | wide area control system                                   |
| WAMS  | wide area measurement system                               |
| ISO   | independent system operator                                |
| NERC  | North American Electric Reliability Council                |
| WECC  | Western Electricity Coordinating Council                   |
| WSCC  | Western Systems Coordinating Council (predecessor to WECC) |
| AEP   | American Electric Power Company                            |
| APS   | Arizona Public Service Company                             |
| BCH   | British Columbia Hydro and Power Authority                 |
| BPA   | Bonneville Power Administration                            |
| PNNL  | Pacific Northwest National Laboratory                      |
| WAPA  | Western Area Power Administration                          |
| DMWG  | Disturbance Monitoring Work Group of the WECC              |
| M&VWG | Monitoring & Validation Work Group of the WECC             |
| PVTF  | Performance Validation Task Force of the M&VWG             |
| COI   | California–Oregon Interconnection                          |
| PACI  | Pacific AC Intertie                                        |
| PDCI  | Pacific DC Intertie                                        |
| pow   | point on wave                                              |
| sps   | samples per second                                         |
| DSI   | dynamic system identification                              |
| FFT   | fast Fourier transform                                     |
| PRS   | Prony solution                                             |

## Appendix A WECC Requirements for Monitor Equipment

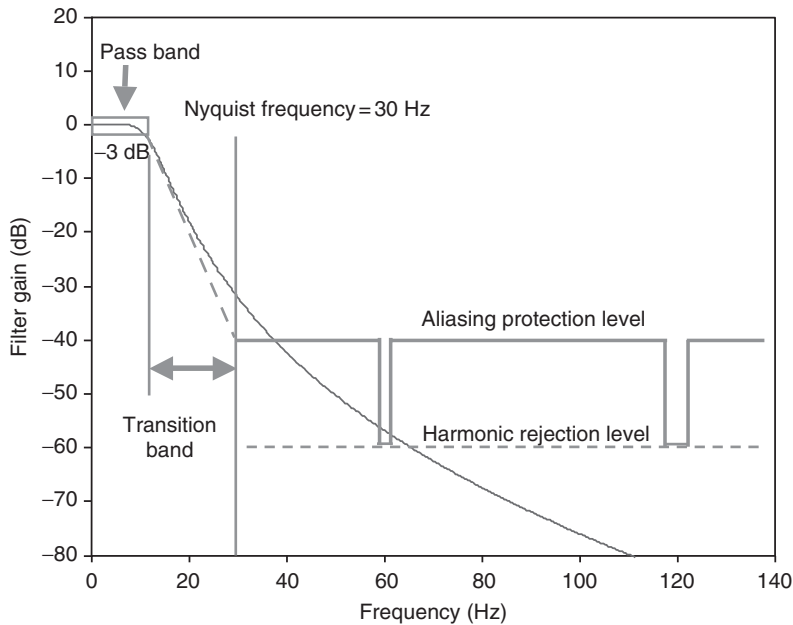
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In 2001, the WECC approved its Dynamic Performance and Disturbance Monitoring Plan to address NERC Planning Standard I.F., *System Adequacy and Security—Disturbance Monitoring*. Within this Plan the WECC established a reimbursement program to assist member utilities with the cost of equipment and maintenance associated with dynamic disturbance monitors at selected system locations.

A monitor shall be judged as meeting basic WECC performance requirements if it satisfies the following technical criteria [53]:

- *Frequency response of overall data acquisition:*
  - is  $-3$  dB or greater at 5 Hz
  - does not exceed  $-40$  dB at frequencies above the Nyquist frequency (a limit of  $-60$  dB is preferred)
  - does not exceed  $-60$  dB at frequencies that are harmonics of the actual power system-operating frequency (for design purposes, assume all frequencies in the range of 59 to 61 Hz)
  - does not produce excessive ringing in records for step disturbances
- *Data sampling rate:*
  - Overall frequency response requirements imply a minimum sample rate that is 4 to 5 times the  $-3$  dB bandwidth of overall data acquisition.
  - For compatibility with other monitors, the sample rate should be an integer multiple of 20 or 30 sps. A multiple of 30 sps is preferred.
- *Numerical resolution and dynamic range:*
  - Resolution of the analog-to-digital (A/D) conversion process must be 16 bits or higher.
  - Scaling of signals entering the A/D conversion should assure that 12–14 bits are actively used to represent them. Signals for which this scaling may overload the A/D during large transients may be recorded on two channels, in which one has less resolution but a greater dynamic range.
- *Measurement noise must be within the normal limits of modern instrument technology.* Noise levels for frequency transducers that are based upon zero-crossing logic tend to be unacceptable.
- *Documentation for the data acquisition process:*
  - must be sufficiently detailed that overall quality of the acquisition system can be assessed
  - must be sufficiently detailed that acquired records can be compensated for attenuation and phase lags introduced by the acquisition system
- *The monitor or monitor system stores data continuously and retains the last 240 h (10 days) at all times without operator intervention.* A monitor that automatically erases the oldest file and stores the newest file will meet this criterion if the buffer area is 10 days or more. If the monitor requires an operator to remove old data to prevent storage overflow, a 60-day buffer is required to accommodate typical practices with monitor systems.
- *The monitor is able to typically store event data files for 60 days without operator intervention.* Since events are inherently unpredictable, this is only a “typical” value based on operating experience. If the monitor stores continuous data, it does not have to store events.
- *The monitor demonstrates synchronization to universal time coordinated (UTC) to a 100  $\mu$ s level or better.* Synchronization to GPS-based timing with suitable technique is preferred. Other approaches may be acceptable.
- Data access is by network, leased line, or dial-up with software for transfer, storage, and data archiving.
- Data formats are well defined and reasonable. Preferred formats for real-time data transfer are those equivalent to or meeting IEEE standards IEEE1344 or PC37.118 or the PDCstream format for concentrator output. The preferred file format is PhasorFile described in PhasorFileFormat.doc (\*.dst) commonly in use in the WECC.

Figure 14.53 represents the filtering requirements in graphical form and applies it to an order 4 Butterworth filter that has a 12 Hz bandwidth and an output rate of 60 sps.



**FIGURE 14.53** 12 Hz Butterworth filter vs. WECC Filtering Standard.

These minimum requirements are indicated as sufficient for meeting WECC needs, but they may not be seen as necessary in some cases. They are intended as quantified guidelines for monitor evaluation, and they are deliberately stated in a simple manner. There are many underlying assumptions, plus considerable room for engineering judgment.

## Appendix B Toolset Functionalities for Processing and Analysis of WAMS Data

Certain functionalities are basic to the efficient and effective use of WAMS data. The DSI toolbox, which has evolved through some three decades of WECC use, is used here as a representative example of what is usually required.

### File reading

- All data types from regional monitor systems. Include data repair and standardized naming of derived signals.
- All data from transient stability programs.
- Data produced during system analysis.

### File writing

- Standardized files for merging, continued analysis, or export to other users. Includes internal documentation, substitution of generic names to conceal data sources.

### File merging

- *Time stamp editing*: Important for merging mismatched files covering the same event
- *Signal resampling*: Required before merging files, adjusting timesteps, etc.
- Automatic renaming of signals to facilitate sorting
- Series and parallel merging of multiple files



## Primary Modules in the DSI Toolbox

| Operation | Module                                                                                                                                                                                                                                                                                                                                                                                                  |
|-----------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1         | <i>Batch Plots</i> : Plot all or selected signals, control axes, send to printer, save to file, manipulate, etc.<br>Can plot any signal against any other, including sample number                                                                                                                                                                                                                      |
| 2         | <i>Angle/freq refs.</i> : Select angle or frequency signal as reference, and subtract from all other signals of that type; estimate frequency from angle signals. At user option, data from this operation overstore or are appended to original data                                                                                                                                                   |
| 3         | <i>Filter/decimate</i> : Input data are filtered and/or decimated. Filter types include high-, low-, and band-pass Butterworth, several kinds of moving average, the BPA “activity filter” for oscillation detection, and filters defined by the user under keyboard control                                                                                                                            |
| 4         | <i>Backload filtered</i> : Data from the filter operation overstore or are appended to present data. Decimated data must overstore present data, due to change in sample rate                                                                                                                                                                                                                           |
| 5         | <i>Fourier</i> : Fast Fourier transforms (FFT), inverse FFT, windowing, autospectra vs. frequency, coherency vs. frequency, waterfall plots, calculate transfer function using non-parametric gain and phase vs. frequency                                                                                                                                                                              |
| 6         | <i>Histograms</i> : Provides statistical information concerning signal activity. Usually preceded by one or more cycles of bandpass filtering are done first                                                                                                                                                                                                                                            |
| 7         | <i>Ringdown GUI</i> : Calculate mode frequencies, damping ratios, mode shapes, and transfer functions from ringdown signals using Prony analysis. Many algorithms are provided                                                                                                                                                                                                                          |
| 8         | <i>Ringdown utilities</i> : Provides tabular and graphical display for ringdown GUI, constructs linear models for control system design                                                                                                                                                                                                                                                                 |
| 9         | <i>AutoCorrelations</i> : Time-domain counterpart to the Fourier processing option. Experimental code seeks modes and damping from system noise response                                                                                                                                                                                                                                                |
| 21        | <i>ModeMeter</i> : Custom codes for estimating mode frequencies, damping ratios, mode shapes, and transfer functions from ambient noise and other signals. Several codesets under development by universities in DOE/EPSCoR project, BPA, PNNL, and others. Some codesets build upon proprietary codes distributed by the Math Works, other National Laboratories, and the NASA Langley Research Center |
| 22        | <i>EventScan</i> : Custom codes that open and scan long file sequences for dynamic events. Not integrated into the DSI toolbox as yet                                                                                                                                                                                                                                                                   |
| 41        | <i>Phasor utilities</i> : Custom codes for deriving phasors from point-on-wave signals. Undocumented toolset for expert users                                                                                                                                                                                                                                                                           |
| 42        | <i>Backload phasor results</i> : Replaces original point-on-wave signals by derived phasors                                                                                                                                                                                                                                                                                                             |
| 51        | <i>Special displays</i> : Custom display codes provided by or for special users. Experimental versions are under development at BPA, perhaps elsewhere                                                                                                                                                                                                                                                  |
| 94        | <i>DownSelect signals</i> : Sorts and/or downselects the signals in active memory                                                                                                                                                                                                                                                                                                                       |
| 95        | <i>Load new data</i> : Loads a new data set for analysis, with optional restart of the automatic processing log                                                                                                                                                                                                                                                                                         |
| 96        | <i>Save results</i> : Saves analysis results and processing log to output file. User can reduce data time span, select between PSMT and SWX output formats; future option will provide extended.dst format compatible with PDC utilities                                                                                                                                                                |
| 97        | <i>Keyboard</i> : Provides direct access to MATLAB Command Window (MCW) during a DSI toolbox session.<br>A primary means for linking into third party toolsets                                                                                                                                                                                                                                          |
| 98        | <i>Defaults on/off</i> : Toggles the default settings that customize processing for efficient performance of predefined task sequences                                                                                                                                                                                                                                                                  |
| 99        | <i>End case</i> : Terminates execution of the DSI toolbox                                                                                                                                                                                                                                                                                                                                               |

## Acknowledgments

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WECC documents cited here are available at <ftp.bpa.gov/pub/WAMS%20Information/>, <http://www.wecc.biz/committees/JGC/DMWG/documents/>, or by special request to the authors.

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